INDUSTRIAL COGENERATION IN CANADA: PROSPECTS AND PERSPECTIVES

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Preface

This study was initiated in the summer of 1986 and completed in February 1987. The survey results incorporated within this study were gathered over the fall and winter of 1986.

The authors would like to express their gratitude, and that of the Institute, to the four-member Advisory Committee of government, industry and utility representatives for the direction, insights and helpful comments provided for this study. Thanks are also extended to the more than 200 industry, government and utility representatives who provided their time and expertise to the study, through the completion of questionnaires and telephone interviews pertaining to the state of industrial cogeneration in Canada. The views and conclusions expressed herein are, however, those of the authors, who accept sole responsibility for any errors or omissions that may exist.

Special thanks are extended to Robert Cottingham for his assistance over the summer of 1986 in the initial project research and preparation of the questionnaires, to Adele Crowley for her computer programming support, and to John Trudeau for his quality graphics work. A final note of thanks is extended to Donna Zimmerman for her endless patience and excellent word processing, and to Shirley Ingstrup for overseeing the publication of this study.

EXECUTIVE SUMMARY

The 1980s have witnessed a dramatic change in the environment for electric power planning in Canada. The rate of growth of electricity demand has fallen off substantially since the 1970s, and most electric utilities have experienced excess generating capacity as the result of construction programs extending into this decade. Given the uncertainty of future demand, utilities and governments are looking beyond traditional sources of utility generating capacity to identify alternative, flexible sources of electric power to meet a part of the forecast load growth.

Industrial cogeneration is one such alternative. Cogeneration is the simultaneous production of electric power and useful thermal energy in one technological process. An industrial cogeneration facility supplies thermal energy (steam) to the production process and electricity to meet a portion or all of a company's plant requirements and, in some cases, provide surplus electric power to the utility grid. The principle advantage of cogeneration over conventional utility electric power generation is in the efficiency of input energy use. A conventional utility power generation technology converts some 35 percent of input energy to electric power. By utilizing both the thermal and electric energy in process, a cogeneration facility can yield overall energy effiency in the range of 80 to 85 percent of input energy.

This study examines the technical, economic and financial aspects of industrial cogeneration development in Canada. Based on the results of a series of surveys and interviews, the study also provides a thorough discussion of the perspective's of industry, electric utilities, and governments as to the costs, benefits, and desirability of adoption of industrial cogeneration technology. This study is not, however, intended to provide a quantitative assessment of the potential for industrial cogeneration in Canada. Nor is it meant to provide a detailed technical and economic analysis of specific cogeneration projects. Rather, its purpose is to investigate the current status of cogeneration development, to analyze the institutional factors which have influenced that development, and to isolate those factors which must be addressed in order to create an environment conducive to the future development of industrial cogeneration in Canada.

From an industry perspective, the direct benefits of cogeneration consist primarily of savings in total energy costs from displacing electricity purchases, and any revenue from the sale of surplus power. Indirect benefits may be derived from improvements in steam quality (temperature and pressure), electricity quality (e.g., reliability) and product quality. Direct costs include the capital cost of installing the cogeneration system, fuel and other operating costs, expenditures for maintenance during periods of downtime, and utility related costs if the facility is connected to the grid (e.g., standby charges, interconnection charges).

From the utility perspective, industrial cogeneration may be viewed as a provincial planning resource. Cogeneration can be seen as both a source of electric power to the grid and as a demand-side option, reducing system capacity requirements through the addition of customer-owned generating capacity. Cogeneration may also be seen to be a competitor for base load, removing industrial demand from the system.

The direct benefits of cogeneration to a utility include savings in capacity and energy costs derived from the reduction, if any, in required system generation capacity, and savings in fuel and operation and maintenance expenses. Indirect benefits may include diversification of fuel mix (e.g., development of wood wastes and other alternative fuels), improved relations with industry and the public, and any reduction in total environmental emissions due to more efficient fuel use. Direct costs to a utility include loss of base load and associated revenue, payments for buyback power, and risks to ratepayers from reliance on cogenerated power.

From a societal perspective, the main concern is the net benefits derived from devoting scarce resources to cogeneration as opposed to alternative uses. This is a broader perspective that goes beyond the 'private' viewpoints of industry and utilities, to encompass such factors as employment impacts and environmental concerns which may not be totally captured in private accounting costs.

The assessment of perspectives on cogeneration on the part of industry, the utilities and government revealed a number of factors encouraging and discouraging cogeneration development in Canada. Many of these relate to technical issues concerning the utility-industry interface which would be addressed at the early stages of implementation. These factors include reliability of the chosen technology, maintenance of the facility, the technical requirements for the actual

interconnection (e.g., allocation of incremental transmission costs, interconnect charges, system integrity, and so on) and other costs associated with the installation procedure. These factors are best addressed by the parties concerned, on a case-by-case basis.

A number of other factors are more generic to the question of industrial cogeneration development. They influenced the following recommendations put forward as measures which would support the establishment of an environment conducive to development of Canada's industrial cogeneration potential.

1. Provincial governments should address the potential for, and limitations of, cogeneration development (along with alternative parallel generation technologies) within the context of long-term electricity supply strategies and options.

2. Where a prospective cogeneration facility exhibits clear economic benefits but inadequate private, financial returns, the relevant provincial government should assess the option of providing direct financial assistance for that development.

3. The federal government should continue its current practice of extending Class 34 accelerated capital cost recovery status to qualifying cogeneration facilities.

4. Utilities' purchase policies for parallel generation should be reviewed with regard to implementing pricing systems which accurately reflect system costs of installing additional generating capacity.

5. Utilities should investigate the option of time-of-use purchase rates for surplus power sold to the grid.

6. Where they have not already done so, utilities should develop and implement policies regarding the wheeling of power for current and prospective cogenerators.

7. Where they have not already done so, utilities should develop guidelines regarding the terms and conditions for interconnection, including technical requirements, charges for standby power, and other aspects of the utility-cogenerator interface.

In the final analysis, the development of industrial cogeneration within an overall electricity supply framework must be assessed from the standpoint of the ratepayer. In all cases where a cogenerator-utility interface is being considered, the ratepayer should be financially indifferent to the interface and, where surplus power is to

be made available to the grid, to the sourcing of incremental power through surplus power sales from the cogenerator or additional capacity from the utility-owned generation system. This implies that cogeneration developments yielding power at costs above the marginal cost of utility system power should not be pursued. It also implies that any benefits arising from utility sourcing of power at prices below system marginal costs should flow through to the ratepayer.

Chapter 1

INTRODUCTION

The 1980s have witnessed a dramatic change in the environment for electric power planning in Canada. Demand growth has fallen off substantially since the 1970s, and most electric utilities have experienced excess generating capacity as the result of construction programs extending into this decade. Given the uncertainty of future demand, utilities and governments alike are looking at alternative, more flexible options for meeting some of the forecast load growth, other than the construction of traditional central power stations. Examples of these options are municipal waste-fired facilities, wind turbine generators, small hydro, photovoltaics, and cogeneration.

Cogeneration is the simultaneous production of power, either electrical or mechanical, and useful thermal energy from a single fuel source. The principle advantage of cogeneration systems lies in their efficiency, and hence fuel savings, compared to conventional thermal power stations. A typical utility generating station based on condensing steam turbine technology converts less than 40 percent of the fuel energy in its boilers to electricity, with the remainder being rejected to the environment. In cogeneration, this waste heat is utilized as a sequential input into another process, for example, in the production of process steam. Therefore, a cogeneration system can convert 70 to 80 percent of the available fuel energy into electricity and useful heat.

Cogeneration can be practiced by industry, in particular at sites which have large continuous steam requirements and significant electricity demand, or which otherwise have access to non-conventional fuels. For example, there is potential for cogeneration in the pulp and paper industry, the production of chemicals, steel and other metals, petroleum extraction and refining, food processing, and textile manufacturing. In addition, cogeneration can by practiced by utilities, where steam is produced as a by-product at thermal generating stations and sold for local industrial or commerical applications. Another source of cogeneration potential is in the commercial sector to serve hot water heating and space heating/cooling requirements, especially in large institutions such as hospitals, hotels and universities.

Recently, improvements in technology have resulted in the development of small packaged units which are capable of producing electricity and hot water for schools, offices and other smaller buildings.

The cogeneration of heat and power by industry can offer several benefits to individual enterprises. First and foremost are the fuel savings associated with recovering waste heat. Furthermore, cogeneration may permit the use of by-products which might otherwise have to be disposed of, like oven gases in steel-making and wood and process wastes in pulp and paper production. Other potential benefits include greater reliability of power supply, cushioning from electricity rate increases, and the opportunity to earn extra revenue through sales of surplus power to the grid.

Industrial cogeneration may also have a number of benefits from the broader perspective of provincial utilities and governments. A more efficient use of conventional and non-conventional fuels can contribute to the goal of conserving scarce energy resources. Cogeneration systems are generally characterized by lower capital investment costs relative to those of central generating stations, due in part to their smaller size and shorter lead time. That is, they can alleviate the siting and environmental problems, as well as the high carrying charges, involved in building large utility-owned power plants. These and other potential benefits--for example, greater flexibility in meeting demand growth, environmental advantages of fuel conservation, reduced transmission requirements, and the promotion of economic growth--suggest an expanded role for cogeneration in which it could become an integral part of the provincial electricity planning process.

At the same time, there are some strong concerns on the part of both industry and electric utilities about the increased development of industrial cogeneration. Individual industries may be reluctant to install cogeneration facilities because of such factors as capital constraints, uncertainty about future fuel and electricity prices, and a lack of skilled personnel. Utilities express concern about their potential loss of load and revenue due to cogeneration, the reliability of a cogenerator's equipment, and the impact of further cogeneration development on system economics.

1.1 Study Objectives and Structure

The purpose of this study is to examine the current environment for industrial cogeneration in Canada, as well as the outlook for

future cogeneration development by industry. While there is also significant potential for cogeneration activity in the commercial/institutional sector, the study focuses on the industrial sector which, given its large thermal requirements, is the predominant source of cogeneration potential in Canada.

The primary focus of this study is on the role of industrial cogeneration as a provincial electric power resource, and on the interface between industry and electric utilities in fostering cogeneration development. The study is not intended to provide a quantitative assessment of the potential for cogeneration, as this has been done elsewhere.[1] Nor is it meant to provide detailed technical and economic analyses of specific cogeneration projects. Rather, its purpose is to investigate the current status of cogeneration development in Canada and to analyze the institutional factors which have influenced that development.

Specific study objectives include:

- to discuss the technical basis for cogeneration and summarize existing and prospective cogeneration technologies;
- to present the economic principles underlying the feasibility of industrial cogeneration;
- to examine briefly the U.S. situation, where cogeneration development has progressed at a more rapid pace due to various economic and regulatory factors;
- to assess the current Canadian situation and contributing factors (electricity and fuel prices, government support, etc.);
- to investigate the attitudes and policies of the different players in the cogeneration field, i.e., industry, utilities, and governments; and
- to offer some policy recommendations with regard to influencing future development in Canada.

The study is organized as follows. Chapter 2 presents the general technical and economic principles of industrial cogeneration, and a discussion of the key factors affecting the financial feasibility of adoption of cogeneration technology. Chapter 3 focuses on the U.S. situation, with a discussion of historical development, current and projected cogeneration capacity, and key issues and concerns. A parallel discussion is provided for Canada in Chapter 4. In Chapter 5,

the different perspectives and policies affecting cogeneration development are analyzed. Finally, Chapter 6 concludes with a number of policy recommendations for the establishment of an economic environment supporting future development of industrial cogeneration in Canada.

1.2 Historical Overview

The cogeneration of heat and electric power by industry dates back to the end of the last century. Through the early 1900s, on-site industrial generation of electricity was more reliable and less costly than utility-generated power. In Canada, much of this development occurred on rivers, because of the abundance of accessible low-cost hydroelectric sites. Where hydro power was not available, companies installed steam turbine generators, including the equivalent of cogeneration systems which recovered steam for production processes.

As residential, commercial and industrial demands for electricity grew, the utility industry expanded and consolidated. Regulation was introduced, and technological advances led to economies of scale in the generation and transmission of electricity. Declining unit capital costs and the availability of relatively inexpensive fuel supplies resulted in a lower cost of service. Except for pulp and paper production, with its access to cheap waste fuels, there was an eventual decline in cogeneration activity as industry turned to higher priority investment projects (i.e., in production plant and equipment). In the United States, industrial generation fell from almost 60 percent of the nation's power requirements in 1900 to only 4 percent of total generation in 1977.[2]

In the wake of the OPEC oil price shocks of 1973/74 and 1979/80, the North American environment for cogeneration has experienced a turn-around. Rising fuel costs, reduced demand growth, and the higher capital costs of large thermal generating stations have significantly increased the cost of utility generation. The situation has been compounded in the United States by the problems faced by the nuclear industry, as well as by general environmental and siting constraints, regulatory opposition, high interest rates, and utility financing difficulties. All of these factors have contributed to the resurgence of interest in cogeneration investment. Legislation introduced in the late 1970s to encourage greater energy efficiency has also spurred cogeneration investment. In particular, the Public Utility Regulatory Policies Act (PURPA) of 1978, which required utilities to purchase surplus electricity from cogenerators at avoided

cost, removed a number of economic and institutional barriers to U.S. cogeneration development.

Recently, falling world oil prices and excess system capacity have resulted in some rationalization of the U.S. cogeneration market (see Section 3.3.2.3). Nevertheless, industrial cogeneration remains an important option for future electricity supply, with some projections of a doubling of total U.S. cogeneration capacity by the year 2000.[3] In Canada, both electric utilities and governments are now considering alternative "demand-side" measures to satisfy demand growth, measures which include cogeneration.[4] Generally, there is a spirit of cooperation emerging in which, for example, utilities are reviewing their purchase policies and rates for surplus cogenerated power. Furthermore, there is some discussion of a more active role for utilities in the promotion of cogeneration investment (e.g., joint ventures with industry). Increased utility participation could ensure a more orderly development of resources, optimal sizing of facilities, greater operating control, and a minimized loss of revenue to the electric utility.

1.3 Terminology

A variety of terminology is used to describe generating facilities which are owned and operated by industry or other non-utility parties. This terminology varies across Canada, with some differences depending on the region or utility jurisdiction. A list of generalized definitions is provided as follows:

- Customer-owned generation (COG) - The generation of electric power from equipment which is owned by a party other than an electric utility. The equipment may be distinct from the grid, in which case the customer serves all of his electricity requirements. Alternatively, the equipment may be interconnected with the grid in which case the customer may receive backup from the system, purchase a portion or all of his energy requirements, and/or sell surplus electricity back to the grid. Examples of COG include small wind turbine generators, industry-owned hydro facilities, and cogeneration systems. In some jurisdictions, such as the Alberta utility network, COG is referred to as "small power production (SPP)."

- Self-generation - The same as customer-owned generation except that in some jurisdictions (e.g., in Ontario)

self-generation relates only to generators which are not interconnected with the grid.

- Parallel generation - Customer-owned and operated generation equipment which is linked with the electric grid.

- Cogeneration - The simultaneous production of power and useful heat in one technological process. Cogeneration can fit into any of the above categories, depending on how it is designed. In a few jurisdictions (e.g., British Columbia), it may also be called a "customer-owned total energy system," in which case the equipment is usually separate from the grid.

Footnotes

[1]See for example Acres Shawinigan Limited, Study of the Potential for Cogeneration in Canada: Industrial Steam Turbine, "Volume 1 - Main Report," Report Prepared for the Conservation and Renewable Energy Branch of Energy, Mines and Resources Canada, Industry Series Publication No. 1 (Ottawa: EMR, December 1979).

[2]Dilip R. Limaye, "Industrial Cogeneration: Trends and Prospects," SRC Paper No. 906-139 (Bala Cynwyd, Pennsylvania: Synergic Resources Corporation, November 1985).

[3]See the discussion of projected U.S. cogeneration capacity in Chapter 3.

[4]Strictly speaking, cogeneration is a supply-side power resource. However, from the perspective of the utility, industry-owned and operated cogeneration facilities are a demand-side option since they result in a reduction in industrial load on the system.

Chapter 2

THE PRINCIPLES OF COGENERATION

The purpose of this chapter is to examine the technical and economic principles associated with the cogeneration of industrial heat and electricity. While it is common to discuss these technological and economic factors separately, they are in fact interrelated. The choice of technology and the relationship between the industry's thermal and electrical requirements, for example, both have an impact on cogeneration economics. Likewise, the economic environment for cogeneration--retail electricity rates, fuel prices, rates for surplus power, etc.--will tend to influence the technology chosen.

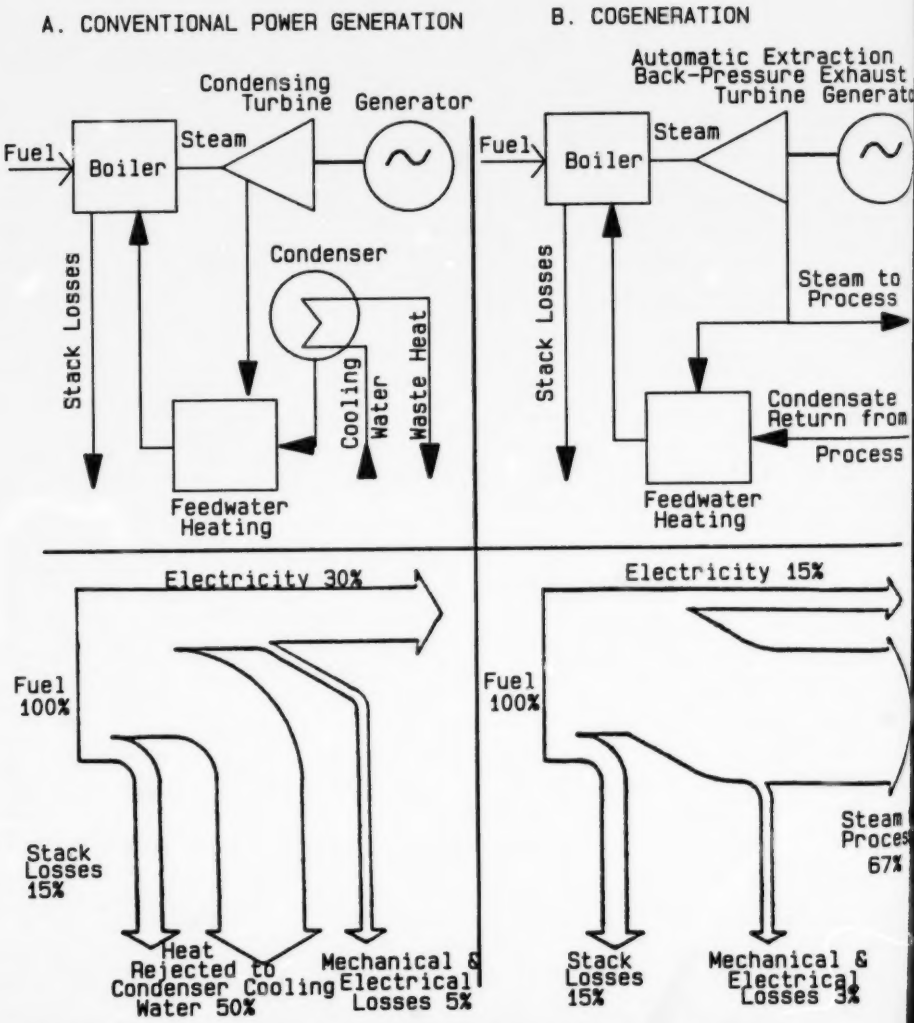
The chapter begins with some background on the rationale for industrial cogeneration. A number of technical issues are then discussed, including the measurement of efficiency, operating conditions for cogeneration, and factors which determine the choice of technology. In the latter part of the chapter, the focus shifts to the economic considerations and the process by which the individual cogenerator makes his financial decisions. A financial evaluation of a hypothetical cogeneration installation is provided, together with a sensitivity analysis on key variables.

2.1 Technical Principles of Cogeneration

The underlying principle of cogeneration is to improve the efficiency of energy use, in particular the fuel efficiency of electric power generation. Less fuel is required to produce useful heat and electricity together than to produce them separately. The differences between a typical utility generating plant and a typical cogeneration system are summarized in Figure 2.1.

In a conventional utility power system, electricity is produced in a "condensing cycle" as follows. High pressure steam is generated in a boiler and passed through a turbine where the steam drops in pressure, driving a generator to produce electricity. The steam is exhausted at low pressure (high vacuum) to a condenser, to be cooled and returned as feedwater to the boiler. The reason for the high

FIGURE 2.1
COMPARISON OF CONVENTIONAL UTILITY POWER GENERATION AND COGENERATION



SOURCE: Alex Juchymenko, Industrial Cogeneration in Ontario.

vacuum level is to extract the maximum mechanical energy from the steam. However, the exhaust heat is of too low a quality (pressure and temperature) to be used in most industrial process applications, and so is rejected to the environment.

Approximately one-half of the heat contained in the fuel is released through the cooling pond (lake) or tower. Another 15 percent is rejected through the stack as flue gases. The result is an efficiency value of only about 35 percent for conventional systems based on condensing turbines.

In a cogeneration system using "back-pressure turbines," the production of electricity proceeds in much the same way as for the condensing cycle. The difference is that the steam is exhausted at a suitably high pressure to be used as a source of process heat. In this case, some two-thirds of the fuel energy is converted to steam, for an overall efficiency of around 85 percent. However, the back-pressure turbine converts less fuel into electricity, relative to the condensing cycle.

Clearly, the advantage of conventional power generation has derived from the economies of scale and lower cost fuels available to electric utilities. Since the primary goal of utilities is to generate low cost electricity, condensing turbines have been the appropriate choice. In terms of putting the waste heat to use, the potential applications are probably limited to space heating of nearby buildings, commonly termed "district heating." The difficulty then becomes one of ensuring a continuous space heating demand for the substantial amount of waste steam rejected from the utility power stations.[1]

As an alternative, the utility itself could develop systems geared specifically to cogeneration. For example, the Nova Scotia Power Corporation installed back-pressure turbine units to serve heavy water plants at Point Tupper and Glace Bay.[2] Again, the utility must locate, or be located, in an area that has significant process heat requirements, since steam cannot be transported over long distances.

In view of these constraints, the greatest potential for development would appear to lie in on-site cogeneration by industry, where the system is designed mainly to serve the cogenerator's thermal and electricity requirements (and, potentially, those of surrounding industry). This industrial cogeneration is the focus of the remainder of the chapter.

2.1.1 Efficiency of Cogeneration Systems

The efficiency advantage of cogeneration relates to its sequential production of heat and electric power. In the majority of cogeneration systems, thermal energy is created as a by-product of electricity generation, as opposed to being produced from full potential fuel energy. Alternatively, electricity may be generated using waste heat from the thermal process (e.g., back pressure turbine technology). This approach has an even higher potential thermodynamic efficiency, since power is produced with no direct fuel consumption.

The actual efficiency that can be achieved in a cogeneration system depends on a number of factors such as the technology used, mode of operation, balance of thermal and electrical loads, and availability of skilled personnel. Operating efficiency can be assessed in terms of the system's "capacity factor" (the ratio of actual electricity generated in a year to the design level of generation) or its "availability factor" (percentage of the year for which the unit does not experience scheduled or unscheduled outages). The following are examples of measures that are used to evaluate fuel use efficiency.

System Efficiency

System efficiency is defined as the quantity of useful or output energy divided by the quantity of energy input:

$$E = \frac{\text{Electric Energy Output (Btu)} + \text{Useful Thermal Energy (Btu)}}{\text{Fuel Energy Input (Btu)}}$$

This measure was used in Section 2.1 above to compare the efficiency of a conventional condensing turbine (35 percent) with that of a back-pressure cogenerating turbine (85 percent). It is based on the first law of thermodynamics relating to the quantities of input and output energy.

Net Heat Rate

Another measure of first law efficiency is the net heat rate of the cogeneration system, which is given by the amount of fuel required to produce 1 kilowatt-hour of electricity:

$$HR_n = \frac{\text{Total Fuel Energy (Btu)} - \left[\frac{\text{Process Thermal Energy (Btu)}}{\text{Process Boiler Efficiency (\%)}}\right]}{\text{Electric Energy Output (kWh)}}$$

This measure makes an adjustment to the usual definition of heat rate ("total heat rate") that is applied to utility generating stations. Specifically, a factor is deducted to reflect the fuel which would otherwise have been consumed in a conventional industrial boiler to supply process heat. Therefore, the measure depends in part on how the cogenerator allocates its primary fuel use between electricity and steam production. Typically, however, a back-pressure turbine system can have a heat rate as low as 4000 Btu/kWh, compared to a value in the order of 9500 Btu/kWh for a utility power plant.

Fuel Savings Rate

A problem with the foregoing efficiency measures is that they do not recognize the relative quality of thermal and electric energy (second law of thermodynamics). Electric energy is of a higher quality because it can be almost entirely converted into mechanical energy, while only a portion of thermal energy can be converted. As a result, a preferable efficiency measure is one that is based on the ratio of electricity to steam production, such as the absolute or relative fuel savings through cogeneration. The fuel savings rate is defined as the fuel saved per unit of useful thermal output due to the displacement of central power generation:

$$r_{fs} = \frac{\left[\text{Utility } HR_t \left(\frac{\text{Btu}}{\text{kWh}}\right) - \text{ Cogeneration } HR_n \left(\frac{\text{Btu}}{\text{kWh}}\right) \times \text{ Electricity Output (kWh)}\right]}{\text{Thermal Energy Output (Btu)}}$$

The implication of this second law efficiency measure is that it will tend to be higher for cogeneration technologies with higher electricity-to-steam ratios. For example, a back-pressure steam turbine has a net heat rate of around 4500 Btu/kWh and an electricity-to-steam ratio in the range of 30 to 75 kWh/MMBtu. A gas turbine cogeneration system has a higher heat rate of 5500 to 6500 Btu/kWh and an electricity-to-steam ratio of between 140 and 225 kWh/MMBtu.[3] Using the middle range of the estimates, the fuel savings rates become:

Steam Turbine: (9500-4500) Btu/kWh x 53 kWh/MMBtu = 0.27
Gas Turbine: (9500-6000) Btu/kWh x 183 kWh/MMBtu = 0.64

Therefore, compared to a back-pressure steam turbine, a gas turbine system has a lower first law efficiency (heat rate) but a higher second law efficiency (fuel savings rate) because of its greater electricity-to-heat output ratio.

Other Measures

Other efficiency measures may be used to value the fuel savings from cogeneration. The underlying notion is that thermal and electric energy differ not only in terms of their quality but also on the basis of their relative economic worth. That is, the cost of purchased electricity is usually greater than the cost of producing steam. A common valuation measure involves multiplying the cogeneration heat rate (Btu/kWh) by the unit fuel cost ($/MMBtu) and then comparing the resulting unit cost of electricity generation (¢/kWh) to the purchase price of utility-generated electricity. The valuation of fuel savings is discussed further in Section 2.2 below.

2.1.2 Technical Feasibility

In assessing technical feasibility, there are certain operating conditions which tend to favour the development of industrial cogeneration. To begin with, cogeneration is most promising for industries which are characterized by substantial thermal energy (and also electricity) requirements. Examples of industries that have large process heat or steam demands are pulp and paper, chemicals, petroleum extraction (enhanced oil recovery) and refining, steel and other metal products, food processing, textiles, and non-metallic mineral products (e.g., glass and cement).

A second condition favouring industrial cogeneration is a reasonable balance in the size (and timing) of thermal and electric loads. In the extreme case where power and steam demands are matched, an optimal level of efficiency may be achieved. In practice, it is rare that a cogenerator's loads are perfectly matched, so arrangements are usually made to buy or sell electricity, store or dump thermal energy, etc.

Even if heat and power demands are reasonably balanced, overall energy requirements may vary throughout the year. Typically, an

industry will be a better candidate for cogeneration if its load factor is high, that is, if it demands steam and electricity on a fairly continuous basis. Several of the industries mentioned above (e.g., chemicals and pulp and paper production) demonstrate load factors of 80 percent or higher. Some firms, however, experience seasonal fluctuations in their energy needs (e.g., certain food processing establishments) or have industrial processes which are not continuous in nature (e.g., the batch process for pulp production). This daily or seasonal variability in load will tend to erode the efficiency gains that can be realized through cogeneration.

To receive the maximum benefit from a cogeneration system, both the electric power generated and the thermal energy produced must be fully utilized. It is generally difficult to match both the cogenerator's thermal and electrical demands with the output of his generation facility. In order to solve the load-matching problem, two approaches are available to the cogenerator:

- Priority Electrical (or Electricity Following): The output of the cogeneration equipment can be matched with the electricity requirements of the plant. Then, if the plant needs more heat or steam than the system can provide, supplementary boilers may be fired. However, this operating mode tends to waste fuel and requires a costly duplication of boilers. If, on the other hand, the cogeneration system produces more heat than can be used on site, then the cogenerator may either dump the excess heat, maintain it in a storage system, or sell it to a nearby user. Sales of surplus steam are limited to users in the immediate vicinity of the plant, since piping costs increase dramatically with distance.

- Priority Thermal (or Thermal Following): An alternative approach is to match the cogeneration system to the thermal demands of the plant. In this case, if there is a deficit in electricity production, it can be met through purchases from the local utility. Alternatively, if the system generates more power than is needed by the plant, the surplus may be sold to nearby users or to the utility grid. Typically, priority thermal is the most economical and preferred mode of operation for an industrial cogeneration facility.

2.1.3 The Choice of Technology

In most cases, the application of cogeneration technology is highly specific to the industrial site and process. Even though the

technology itself is sometimes "off the shelf," it may have to be fit into the current plant configuration and production process. That is, some cogeneration applications may involve new plant facilities, while others may take the form of retrofits to existing boiler systems.

There are a variety of factors which determine the technologies available to a cogenerator, and which influence his ultimate choice of technology. These determining factors include:

- Thermal Energy Requirements - A key consideration in the choice of cogeneration technology is the quality of thermal energy required for the production process. The quantity of required steam is measured in pounds per hour. For cogeneration systems, a minimum heat demand of 100,000 lbs/hr is often specified, although Canadian applications have included demands in the order of 50,000 lbs/hr. The quality of thermal energy relates to its heat content in Btu/lb, and is a function of pressure (in psig) and temperature (°F). For example, if a particular process requires steam at high temperature and pressure, then the technology chosen may be a combustion turbine system which produces exhaust gas at temperatures of up to 1100° F.

- Electrical Energy Requirements - Also important to the selection of technology is the amount of electric power required at the industrial site. Certain cogeneration technologies such as combined cycle systems and diesel engines are characterized by comparatively high electricity-to-steam ratios, while others such as back-pressure steam turbines are geared more towards the production of process steam. The desirable level of electricity generation may depend not only on the cogenerator's power needs but also on the amount of surplus electricity that can be sold to other local users, the utility, or more distant company plants (through wheeling of power).

- Operating Characteristics - As described earlier, the technical feasibility of cogeneration is influenced by the extent to which energy loads are reasonably continuous or are subject to seasonal or daily variability. The difficulty with matching a cogeneration technology to variable steam and/or power requirements is that most technologies have relatively fixed thermal-to-electric outputs. Some flexibility can be achieved at the expense of additional equipment, fuel costs, or complexity of the system. For example, gas turbine systems may be equipped with supplementary fuel-firing in the waste heat boilers, in order to increase the production of process steam.

- Availability of Fuels - The choice of technology is also a function of the range of fuel sources available to the cogenerator. Fuel availability will, in turn, tend to vary by region and by industry. Certain industries may have access to combustible wastes or waste heat, in addition to conventional fossil fuels. In some cases the economic feasibility of cogeneration may turn on the use of waste by-products (e.g., pulp and paper companies that burn hog fuel or spent pulping liquor). Therefore, a steam turbine cycle will be employed since it is able to accommodate different types of fuel, including solid waste and wood and process wastes. In general, the cogenerator may be concerned with the fuel flexibility of technologies, so that he can hedge against the cost and availability of particular fuels.

- Fuel Use Efficiency - As discussed in Section 2.1.1, cogeneration technologies differ according to their efficiency of fuel use. Moreover, the efficiency ranking of technologies will depend on what measure is used--for example, first law efficiency measures such as the net heat rate or second law efficiency measures such as the fuel savings rate.

- Physical Site Limitations - Another factor to be considered in evaluating different technologies is the amount of plant space (i.e., floor space) available for installing and adequately operating the cogeneration equipment. Not only must there be sufficient space, but the equipment should be appropriately placed for accessibility to the production process.

- Retrofit versus New Facility - Related to the issue of site limitation is whether the cogeneration system involves a retrofit to the existing plant or a new installation. Most cogeneration has been retrofitted into the existing boiler plant and production process. As a consequence, cogeneration tends to be highly site-specific. If the boilers are not due for replacement, and floor space is constrained, then one approach is to add gas turbines for generating electricity and to alter the current boilers to allow for waste heat recovery from the exhaust gas.[4] This option is not always available, being dependent on the compatability of the existing boiler technology with the characteristics of the turbine (e.g., air flow requirements). In some industrial applications, cogeneration may be rendered unfeasible by site constraints or by the excessive costs of having to make process modifications.

- Equipment Size - Cogeneration technologies come in a range of unit sizes, and the ranges vary by technology. In addition, each technology is subject to different

economies of scale, which can have a significant impact on economic feasibility. Under a priority thermal operating mode, it is the process thermal requirements that determine the sizing of a cogeneration system. Given the differences in electrical ouput between technologies, the choice of technology will affect the unit size (in MW) required to meet a given thermal load. For example, the unit size will tend to be larger for a gas turbine than a steam turbine, since the former has a higher electricity-to-steam output ratio. In the case of a steam turbine fired by solid fuels, however, the inclusion of the fuel handling system would normally result in a total physical system size far in excess of a gas turbine system. It is important to bear the full-cycle space requirements in mind when comparing competing technologies.

- Personnel Requirements - Yet another factor is the personnel requirements, and in particular the maintenance requirements, of the cogeneration technology. Industries may lack the skilled in-house personnel to manage and operate a complex cogeneration system. Steam turbines, for example, are generally characterized by lower maintenance requirements than gas turbines. This is due, in part, to the fact that gas turbines are often used to supply peaking generation, and so undergo swings of start-up and shut-down.

- Other Factors - Other factors which affect the selection of technology include: (1) management attitudes, and (2) the ability of the cogenerator to interconnect with the grid. Industrial management tends to be conservative in its investment decisions, especially with respect to energy projects. Therefore, in industries that have experience with cogeneration, it is common to maintain the traditional technology such as steam turbines. As for the ability to sell surplus electricity or steam, this can have an influence on the technology chosen through the size of the cogeneration system and the electricity-to-steam ratio.

In general, flexibility may be an important criterion for choosing among technologies. This can include the use of different types of fuel, the potential for varying electricity and steam outputs, the ease of installation, operating flexibility, and the ability to accommodate future process changes.

2.1.4 Description of Technologies

There are two fundamental approaches to the integration of cogeneration into the industrial process. The approaches differ according to which is produced first, electric or thermal energy.

- Topping-Cycle Systems are the most common type of configuration for industrial (and other) uses. In a topping-cycle facility, energy is used first at high temperature and pressure to generate electricity. Then the low-pressure exhaust steam is used to supply thermal energy for the production process.

- Bottoming-Cycle Systems may be applied to industrial processes which require very high-temperature heat--for example, in certain primary metal, metal products, and non-metallic mineral products industries. Thermal energy is produced first for applications such as steel reheat furnaces, aluminum remelt furnaces, or glass kilns. Waste heat is subsequently extracted from the exhaust steam and used to drive a turbine (Rankine Cycle). Although its use is more limited, the bottoming cycle has higher thermodynamic (or fuel conservation) potential in the sense that no incremental fuel is burned to generate electricity.

Individual technologies are usually classified on the basis of their prime mover (e.g., steam turbine or gas turbine). These technologies are described below, classified by conventional or mature cogeneration technologies (all topping-cycle systems) and new or emerging technologies.

2.1.4.1 Conventional Technologies

Steam turbine systems are the most prevalent form of cogeneration in Canada today. Electricity is generated in a turbine and then process steam is extracted at the last stage (back-pressure turbines) or at an intermediate stage (extraction turbines). The primary purpose of steam turbines is to produce thermal energy; that is, electricity production is traded off against the need to generate large amounts of process steam.

The advantages of steam turbines include their ability to burn many types of fuel (e.g., coal, oil, natural gas, wood, and wastes), high reliability, high overall fuel efficiency, and a wide range of equipment sizes. Among the disadvantages are their long lead time relative to other technologies and their lack of flexibility in varying thermal-to-electrical output. In the case of a back-pressure turbine, the production of electricity and steam are directly related, so that a drop in steam requirements leads to a reduction in power generated. A

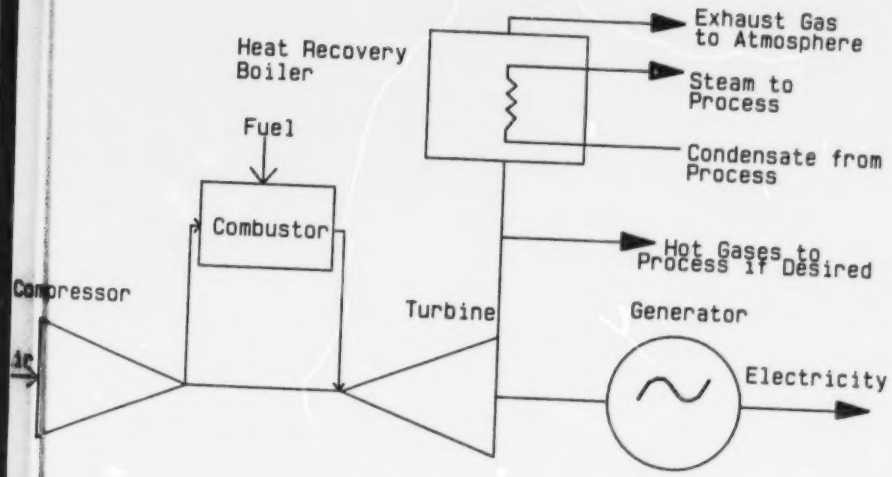
condensing steam turbine with steam extraction allows for improved flexibility, to the extent that a change in steam demand by process will not affect the electrical output and, conversely, a change in electric demand will not affect the extraction steam flow to process. In this case, the amount of steam flow to the condensor is varied to offset the energy demand changes in process.

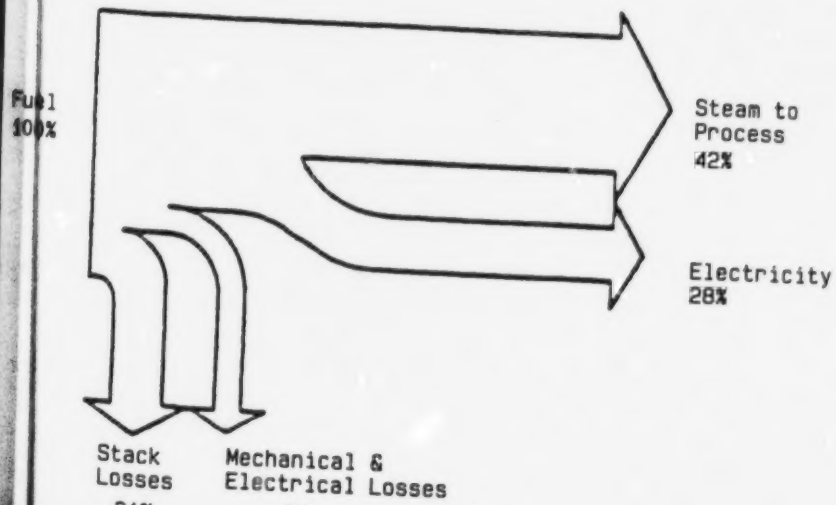
Gas turbine systems constitute the second most common technology that is used for cogeneration in Canada. In a gas turbine facility, atmospheric air is drawn into a compressor where it is compressed. The air flows from the compressor to a direct fired combustion chamber where it is heated and then passed through a turbine to produce electric energy. The exhaust gases from the gas turbine are then passed through a Heat Recovery steam generator to recover additional energy in the form of steam. Because of the relatively high temperature of the exhaust gases, high pressure steam can be generated and passed through a steam turbine to increase the electricity-to-steam output of the designed cycle. The primary goal of the gas turbine is to generate electric power. Operating in a simple cycle mode with no heat recovery, a gas turbine cogenerator will have an electrical (thermodynamic) efficiency of between 20 and 35 percent (see Figure 2.2).

In terms of its advantages, gas turbine technology is relatively easy to transport and install, is available in various unit sizes, has a high reliability factor, and responds rapidly to changes in electricity load. Additional operating flexibility can be realized by supplementary fuel-firing in the waste heat boiler, which boosts steam production at comparatively low incremental cost. The main disadvantage of gas turbine systems is their use of premium fuels (natural gas and distillate fuels). However, new technologies based on coal- and biomass-derived gases and liquids may help to conserve nonrenewable fuel sources, as well as to insulate against the uncertainty of future natural gas prices.

In combined cycle cogeneration, the steam generated in a gas turbine heat recovery boiler is used to drive a steam turbine. The exhaust from the turbine cycle then becomes the source of steam for the industrial process. Basically, this is equivalent to combining a gas turbine topping cycle and a steam turbine bottoming cycle (see Figure 2.3, which provides a schematic for a combined gas turbine-back pressure exhaust steam turbine cogeneration cycle). The result is a greater electrical efficiency (as much as 40 percent in the absence of

FIGURE 2.2
GAS TURBINE COGENERATION SYSTEM





SOURCE: Canadian Energy Research Institute.

FIGURE 2.3
COMBINED CYCLE COGENERATION SYSTEM

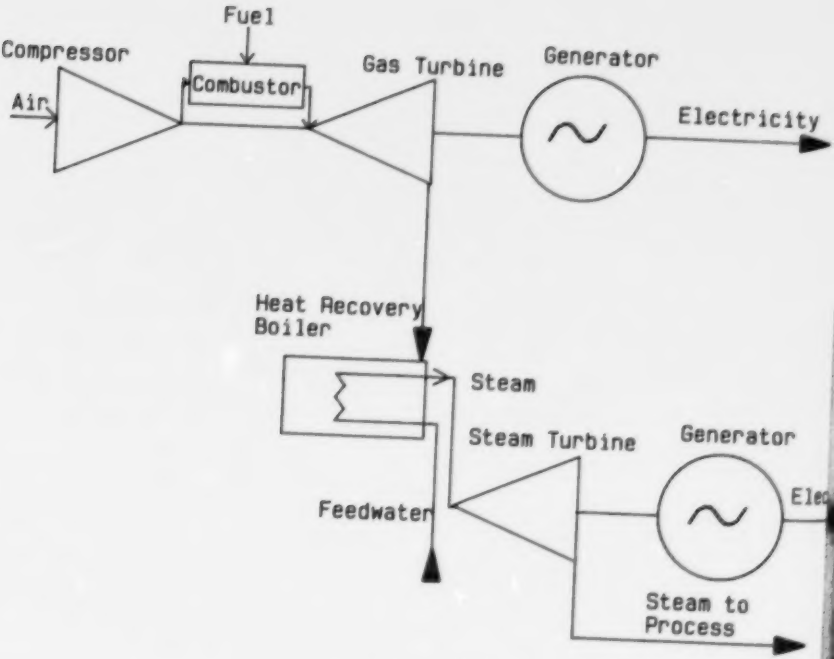
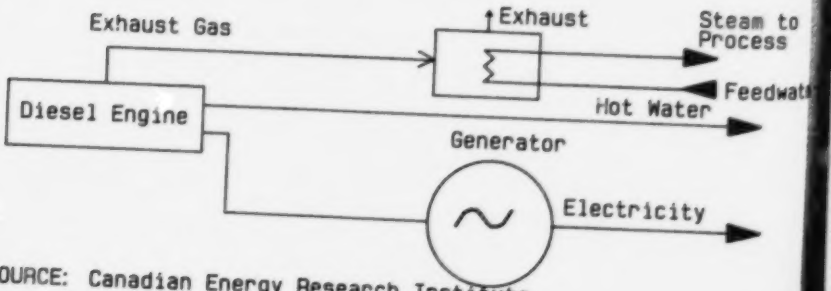


FIGURE 2.4
DIESEL ENGINE COGENERATION SYSTEM



SOURCE: Canadian Energy Research Institute.

process heat requirements) than that produced by either a steam turbine or gas turbine alone. Total fuel use is higher under a combined cycle system, but the rate of fuel savings is also higher because of the amount of electricity generated.

Combined cycle plants tend to be used in large industrial applications such as the chemical and petroleum refining industries. For example, this technology has been applied with availability factors of up to 97 percent at Dow Chemical plants in Sarnia, Ontario and Fort Saskatchewan, Alberta.[5] There are a number of advantages in common with gas turbine systems, including the ability to vary steam and electricity output by auxiliary fuel-firing. A common disadvantage is the reliance on premium fuels; however, future combined cycle systems will be able to incorporate fluidized bed combustors, that can burn various types of solid fuel, or coal gasification plants designed to produce low Btu fuel.

Diesel engines (internal combustion engines) rank among the highest of the major topping-cycle technologies in terms of their electricity-to-steam ratios. The engine itself drives a generator to produce electricity, while the heat given off is used for thermal energy requirements. This heat is extracted from the water jacket cooling system, as well as from the engine's exhaust gases which are passed through a waste heat recovery boiler (see Figure 2.4).

Diesel engines have certain advantages in that they are available in small unit sizes, are easily transported and installed, and provide electricity almost instantaneously without the need for boiler warmup. They too, however, require the use of premium fuels (natural gas, distillates, or residual fuel oil). They also produce low-pressure steam that is typically better suited to space heating than process heating applications. As a result, the potential for engine-based systems would appear to be greater for isolated Canadian communities, where electricity costs are high and waste heat can be used in district heating.

Table 2.1 presents a summary comparison of the four technologies, in terms of some key technical features. In addition, the table includes estimates of 'typical' intalled capital costs for the complete cogeneration system.[6] As a general rule, steam turbine and combined cycle systems are more economic for relatively large unit sizes (i.e., in excess of 10 MW). Gas turbine systems are useful in intermediate

TABLE 2.1

COMPARISON OF CONVENTIONAL TOPPING-CYCLE TECHNOLOGIES

Features	Steam Turbine Cogenerator	Gas Turbine Cogenerator	Combined Cycle Cogenerator	Diesel Engine Cogenerator
Unite size (MW)	.5 up	.1 - 200	3 - 400	.075 - 30
Fuels used[a]	Any	Natural Gas Distillates	Natural Gas Distillates	Natural Gas Distillates Residual Oil
Availability (%)	90-95	90-95	77-95	80-90
Installation lead time (years)	1-3	0.75-2	1-3	0.75-2.5
Service life (years)	25-35	15-20	15-25	15-25
System efficiency (%)	65-85	65-85	65-85	40-80
New heat rate (Btu/kWh)	4000-6000	5500-6000	5000-6500	6000-7500
Electrical efficiency (%)	15-30	25-35	35-40	35-40
Electricity-to-steam ratio (kWh/MMBtu)	30-75	140-225	175-320	350-700
Installed capital cost ($/kW 1985)[b]	500-1500	400-800	200-600	N/A[c]
Environmental emmission	SOx, NOx	NOx	NOx	NOx, CO
Applicability	Most Common technology. Best suited for low power/ steam requirements.	Also common technology. Main goal is power generation.	Used in large industrial applications. Best suited for high power/steam requirements.	Highest power/steam ratio. Best for small cogenerators and space heating.

SOURCE: U.S. Office of Technology Assessment, Industrial and Commercial Cogeneration; S. David Hu, Cogeneration; and U.S. Department of Commerce, Industrial Cogeneration--What It Is, How It Works, Its Potential.

[a]Excludes future potential fuels.
[b]Refers to 'typical' system costs.
[c]Not Available

(1-10 MW) to large applications, while diesel engines are well-suited to small scale cogeneration.

2.1.4.2 Emerging Technologies

The cogeneration technologies outlined above are all mature and have been commercially available for many years. There are also some new or emerging technologies which are characterized by varying degrees of development and economic feasibility. The following are examples of emerging cogeneration technologies:

- Organic Rankine Turbines are based on a steam turbine bottoming cycle, but with the substitution of organic working fluids (e.g., toluene, propane, benzene, and freons) for steam. Their principal advantage is that they can generate electricity from very low grade waste heat, at temperatures as low as 200° F.

- Stirling Engines operate in a similar manner to automobile engines, with gas compressing and expanding in a cylinder to drive a crankshaft. These engines have the potential to use different fuels (e.g., coal- and biomass-derived gases and liquids) and demonstrate high efficiencies of fuel use.

- Fluidized Bed Combustion Systems involve the burning of fuel particles at high temperatures in a bed of limestone. Fluidized bed combustors permit the use of a variety of solid fuels (coal, petroleum coke, wood waste, municipal waste, etc.), and also avoid the high capital costs of flue gas desulphurization equipment. However, consideration must be given to the capital and operating costs of preparing and handling the limestone.

- Gasification technologies can conceivably be used in conjunction with any of the four main cogeneration cycles to produce power from coal- or biomass-derived synthetic fuels. Advantages include reduced costs for the transportation, storage and handling of coal, and a viable solution for the disposal of municipal waste.

- Fuel Cells are electrochemical devices that convert the chemical energy of a fuel directly into electricity, with no intermediate combustion cycle. This technology has numerous advantages including its modular nature, high electric efficiency, good load-following capability, and low emissions.

- Cheng Steam Injection Cycles entail the injection of steam into a gas turbine in order to increase electrical output. At the expense of higher capital costs, the cycle may accommodate industries which experience wide fluctuations in their thermal and electrical loads.

- Kalina Cycles are a variation on the organic Rankine cycle,using an ammonia-water mixture and adding an initial distillation step to the cycle. The results are a high thermodynamic efficiency in low level heat applications and increased generation of electric power.

2.2 Economics of Cogeneration

Economics are the critical element in determining the feasibility of cogeneration development. Cogeneration can be evaluated in terms of its impacts on several different parties, for example, the individual industry, the electric utility, and society at large. The methodology for evaluation, as well as the quantification of costs and benefits, will vary with the perspective taken.

These different perspectives on cogeneration are discussed further in Chapter 5. For now, we focus on the "private" economic viewpoint of a company considering investment in cogeneration equipment. In this case, the economic decision is relatively straightforward. The company must compare the estimated costs and benefits of the cogeneration system against the costs and benefits of the existing energy network--i.e., purchases of electricity from the utility, and steam generation in low-pressure boilers. Benefits from cogeneration relate primarily to savings in purchased electricity costs, while costs consist mainly of the capital and operating expenditures of the cogenerating facilities.

This basic decision-making framework applies to a company that intends to use all of its cogenerated power. If the firm also plans to have surplus electricity available for sale, then the economic evaluation should include the expected revenue from those sales.

2.2.1 Economic Criteria

The economic feasibility of cogeneration depends on technical factors such as the quantities of thermal and electrical energy required by the production process, the technology being considered, and any anticipated changes to the industrial plant or process. In addition, there are four key economic variables which determine the

feasibility of a cogeneration installation. These variables, along with other important economic factors, are examined below.

2.2.1.1 Capital Costs

For the prospective cogenerator, the up-front costs of cogeneration equipment are a major consideration. Generally speaking, the capital costs which are attributed to the cogeneration capacity are the incremental costs over and above those ascribed to the existing thermal system. That is, the cost of buildings, low pressure boilers, etc., already installed is allocated to the steam side of the operation. Cogeneration capital then accounts for expenditures on upgrading of boiler facilities (to high pressure capability), turbine-generators, building modifications, pollution control equipment (if required) and other related items--for example, installation labour, engineering services, and interest during construction. As well, any capital costs incurred by operating in parallel with the utility system (e.g., interconnection equipment) should be taken into account.

Actual capital costs will vary significantly from one cogeneration facility to another. Typically, unit ($/kW) costs depend on the technology selected, size of the facility, fuel used, and site characteristics (plant location, availability of space, etc.). There are economies of scale associated with installing larger cogeneration units. Gas turbine technology tends to cost less than steam turbine technology for a comparable unit size, in terms of both turbine and incremental boiler investment. In the case of steam turbine units, boilers that burn forest biomass are normally more expensive than fossil-fueled boilers because of the relative cleanliness and quality of the fossil fuels.

2.2.1.2 Operating Costs

The most important element of operating costs is the cost and availability of fuel supplies over the life of the cogeneration facility. Across Canada, there are considerable regional differences in the price of fuel. As well, some industries have access to combustible by-products, such as furnace gases in iron and steel production and wood and process wastes in the pulp and paper industry. Generally, these waste fuels are available at low cost and may lead to reduced requirements for disposal.

Over the long term, the economics of cogeneration depend to a large extent on the change in fuel costs in relation to the price of utility-generated electricity. If the cost of fuel rises faster than the price of electricity, then the energy cost savings through cogeneration will be eroded. Therefore, the feasibility of a cogeneration project will be influenced by the "uncertainty bands" specified for different fuel types. The specification of these bands will, in turn, depend upon perceptions regarding the future world oil market, the impact of natural gas deregulation, marginal sources of utility generation, extended access to waste fuels, and other factors.

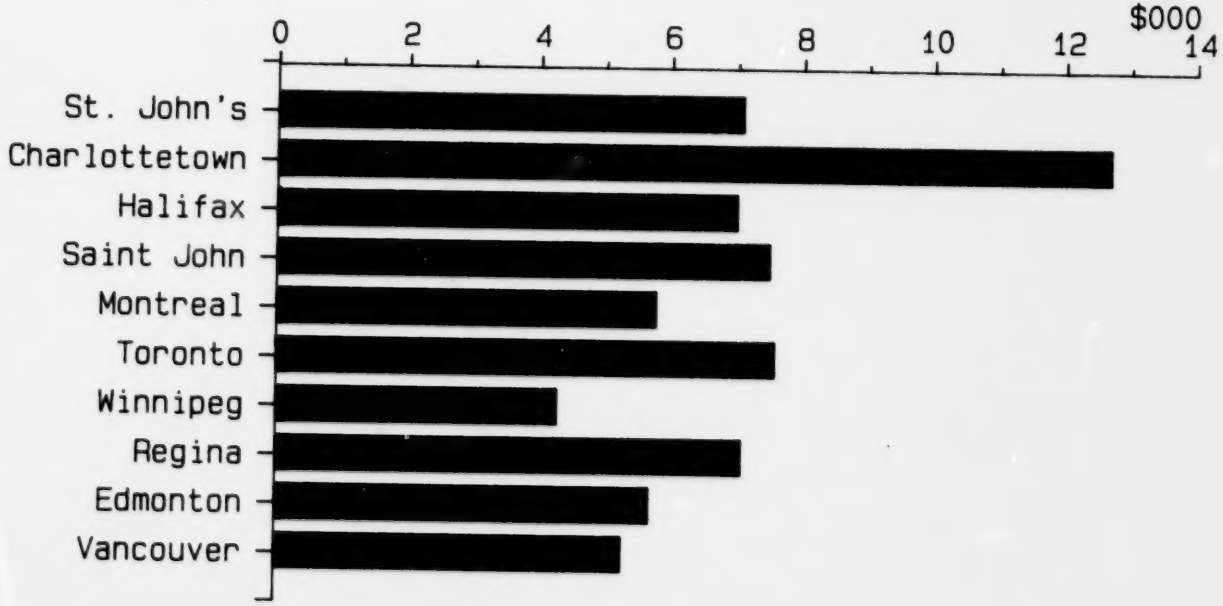
Aside from fuel, operating expenses include the costs of labour to run the cogeneration equipment, maintenance, property and sales taxes, and insurance. As in the case of cogeneration capital, all costs are evaluated on an incremental basis. For operation and maintenance (O&M) costs, the primary sources of uncertainty lie in personnel experience and performance of the equipment. In particular, there can be a sharp buildup in maintenance costs if the cogeneration system undergoes frequent and prolonged periods of production downtime.

2.2.1.3 Cost of Electricity

The cost of utility-generated power to the prospective cogenerator is crucial to an evaluation of the savings from displacing electricity purchases with cogeneration. As shown in Figure 2.5, the cost of industrial electricity varies from province to province depending, in particular, on the generation mix. As a result, the economics of cogeneration will tend to be most favourable in regions that are relatively more reliant on expensive fossil-fired generation (i.e., high cost oil and gas-fired units).

Industrial and commercial electricity prices are made up of two components: (1) a demand charge, designed to recover the customers's share of fixed (capital) costs; and (2) an energy charge, related to the volume of energy actually consumed. The average price of electricity varies inversely with the customer's load factors. That is, the higher the load factor the lower the average unit (per kWh) cost of purchased electricity. Most of the industries with technical potential for cogeneration--for example, chemicals, refining and pulp and paper production--require electricity on a fairly continuous basis, in some cases, 24 hours per day, 50 weeks or so per year.[8]

AVERAGE MONTHLY INDUSTRIAL ELECTRICITY BILLS
SELECTED CITIES, 1985



SOURCE: Statistics Canada Catalogue No. 57-203.

Note: Based on a 500kW billing demand and monthly consumption of 100MWh.

Utility rates reflect the average "embedded" cost of generation, meaning that the cost of new, more expensive facilities is rolled in with the cost of the existing system. Generally, this average cost is lower than the cost of the marginal generation source.[9] In addition, it is common to use a declining block industrial rate structure, in which the unit price of electricity falls as consumption increases. Both of these factors, along with the presence of excess generating capability, have tended to keep industrial power rates relatively low in Canada.

Another aspect of utility pricing which has implications for cogeneration is the charge applied to backup or standby power. A cogenerator requires backup resources to meet plant requirements during startup of his equipment, as well as during planned and unplanned outages. He may meet these requirements either by building redundancy into the cogeneration system, or by relying on external supply sources. If the utility (or some other supplier) provides standby service, then the price for the service must be factored into the cost of cogeneration.

2.2.1.4 Buyback Rates

Some cogeneration systems may result in surplus electricity which can be sold to the grid, either on a short-term "as-available" basis or on a longer-term firm basis. In this case, an economic evaluation should include the anticipated revenue from the sale of excess power. A number of utilities have a purchase policy for customer-owned generation, stipulating buyback rates and the conditions under which power will be accepted.

As described in Section 2.1.2, the majority of cogeneration systems are designed for a Priority Thermal mode of operation, whereby the system is sized to meet the thermal needs of the process. Electric power requirements can then be balanced through purchases from the utility. It is, therefore, unlikely that a cogenerator would optimize his system primarily with respect to the potential revenues from surplus electricity sales, unless the purchase rates were sufficiently high to justify the incremental capital and operating costs incurred.[10] Nevertheless, buyback rates can be a significant item on the "benefit side" of the cogeneration equation, particularly for industries which experience fluctuations in their load.

2.2.1.5 Other Factors

Among the other important variables for cogeneration economics are:

- Capacity Factor - Typically, the higher the annual capacity factor, the lower the unit cost of the cogeneration system. Capacity factors depend on both the degree of utilization and operating performance. The economics will tend to be more favourable for industries with continuous electricity requirements than for those whose loads occur during only part of the day or year. In terms of reliability, there is a risk that capacity factors will deteriorate due to unanticipated outages.[11] Not only will this increase per kWh costs, but it may result in significant expenditures on backup generation.

- Heat Rate - The heat rate (in Btu/kWh) is a measure of the technical efficiency of a cogeneration system. A low heat rate has a positive impact on project economics to the extent that a lower heat rate means that less fuel must be consumed to generate a given amount of electricity. As a result, the cogenerator's operating costs will be smaller. Generally, it is the lower heat rate (higher efficiency) of cogeneration units relative to conventional power stations that justifies their use of premium fuels such as natural gas and fuel oil.

- Fiscal Regime - Two additional variables which enter the economic evaluation are the company tax rate and the Capital Cost Allowance (CCA). Cogeneration facilities which consume fossil fuels at a rate no greater than 7000 BTUs per kWh qualify for the Class 34 CCA, allowing investment to be written off against taxable income as follows:

First Year	25%
Second Year	50%
Third Year	25%

- Escalation Rates - Aside from changing fuel and electricity costs, there should be an allowance made for escalation in capital and O&M costs.

- Miscellaneous - These may include the corporate interest rate, plant life, and installation period of the facility.

2.2.2 Financial Criteria

A company interested in cogeneration investment will evaluate that investment in the same manner as it would any other capital project. There are two main types of financial criteria normally used by industry:

- Rate of return on investment (ROI, also know as IRR, Internal Rate of Return); and
- Payback period.

The rate of return on investment specifically takes account of the time value of money and the cash flows over the life of the facility. It is defined as the interest or discount rate that equates the present value costs (capital and operating) of the project with the present value benefits (fuel savings and surplus electricity revenues). The ROI can be calculated on a before-tax or after-tax basis, although most firms prefer the after-tax specification. In any case, the company compares the estimated rate of return on the investment with a target minimum value known as the hurdle rate.

The payback period offers a simple alternative for assessing project feasibility. It refers to the time period required to recover the initial investment, and is computed by dividing the capital cost of the facility by the savings in annual operating costs. The payback is determined on a gross before-tax basis, with no accounting for the time value of money. To evaluate feasibility, the company compares the calculated payback against a target maximum.

2.2.3 Financial Evaluation

Financial evaluations can be performed under a range of assumptions for the key economic variables described in Section 2.2.1. This allows the company to examine the impact of uncertainty on the economics of the project. Sensitivity analyses may be carried out for any number of items, such as cogeneration capital cost, unit size, fuel cost, electricity rates, capacity factor, and escalation in fuel and electricity prices.

To investigate the factors determining the financial profile of a cogeneration installation, a financial evaluation of a hypothetical

cogeneration project was undertaken. The assumptions underlying the evaluation are provided in Table 2.2. The project is a 10 MW gas turbine cogenerator, installed at an investment cost of $5.4 million ($540 per kW of installed capacity).[12] Installation is assumed to take place in 1987. The cogeneration facility has a service life of 15 years, with scrap value and decommissioning charges assumed to be zero at the end of the service life. Electricity rates are assumed to increase at an average real rate of 2 percent per year over the life of the plant.

Electricity generated by the facility is assumed to offset electricity requirements at the plant-site. Accordingly, the energy generated is valued at the industrial rate for the demand-energy configuration being analyzed. Thermal power generated by the facility is valued at the Btu-adjusted energy price of the input fuel, in this case natural gas. Therefore, the facility is assigned revenue credits for both the process steam heat utilized in the plant and the electricity generated by the cogeneration installation. Expenses for the facility are comprised of the initial capital investment, the fuel cost for operation of the facility, and operation and maintenance expenses. The latter are valued at 2 percent of the initial investment and are assumed to remain constant in real terms over the life of the facility.

Before- and after-tax internal rates of return are calculated for the base case financial evaluation and a number of sensitivity or "what if" cases. The payback period is also provided for each case. After-tax rate of return is based on a 44 percent income tax rate and application of the Class 34 accelerated capital cost allowance schedule.

2.2.3.1 Base Case Results

The base case analysis was performed using standard industrial electricity rates for Ontario as of January, 1987, provided by the Ontario Hydro rates department. As discussed above, industrial purchase rates are used, rather than the utility's buyback rates, because of the assumption that the electricity generated by the facility is used to offset the electricity requirements of the cogenerator, rather than for sale to the utility grid. Natural gas fuel prices are estimated burner-tip prices for a large industrial consumer in southern Ontario. The electricity rates and fuel prices are shown in Table 2.2.

TABLE 2.2

FINANCIAL EVALUATION: GAS TURBINE COGENERATOR
PROJECT CHARACTERISTICS

Generating Capacity (kW)	10000
Capital Cost ($ 000s)	5400
O & M Cost ($ 000s)	108
Energy Price ($/GJ)	3.05
Fuel Price ($/cu.M.)	0.088
Heat Rate (MJ/kWh)	12.0
Heat Recovery (%)	60
Load Factor (%)	91
Efficiency: Boiler (%)	80
Generator (%)	91
Electricity Rates: Base Case	
Demand Charge ($/kW)	8.15
Energy Charge (¢/kWh)	2.13
Combined Rate (¢/kWh)	3.33
Fiscal Variables	
Tax Rate (%)	44
CCA (Class 34)	25%; 50%; 25%

SOURCE: Canadian Energy Research Institute, January 1987.

Base case financial projections are shown in Table 2.3. All values are expressed in current dollars, assuming an average annual inflation rate of 4.0 percent. The facility yields a before-tax internal rate of return (IRR) of 29.6 percent at the end of service life and an after-tax IRR of 29.0 percent. The project has a payback of 4 years on a before-tax revenue basis.

2.2.3.2 Sensitivity Cases

To investigate the effect of changes in key input variables on the financial profile of a cogeneration installation, a number of sensitivity cases were performed on the base case evaluation program. In each case, the impact of the changes on before- and after-tax IRR and payback period were recorded.

Geographic Location

Electricity rates and fuel prices vary considerably across Canada. To investigate the impact of geographic location on the financial feasiblity of a cogeneration installation, the evaluation program was run using electricity rates and fuel prices in place in southern Alberta. Standard industrial electricity rates, provided by TransAlta Utilities Corporation, were used to value the electricity produced by the facility. These are provided below.

Demand Charge	$ 10.57/kW/month, 115kv
Energy Charge	1.11 ¢/kWh
Combined Rate	3.04 ¢/kWh

The financial evaluation yields a before-tax IRR of 21.7 percent at end of service life, roughly 73 percent of the Ontario case. After-tax IRR is 17.1 percent or just under 60 percent of that resulting from the Ontario case. Payback is calculated at 5 years. The main reason for the poorer financial performance under the Alberta case is the 20 percent decline in electricity offset credits accruing to the installation, relative to the Ontario case. This is due to the lower industrial electricity rates charged in southern Alberta. The electricity offset credit would be lowered further by inclusion of the 18.5 percent Alberta Income Tax Rebate applicable to industrial electricity rates.

TABLE 2.3

FINANCIAL EVALUATION: GAS TURBINE COGENERATOR
BASE CASE RESULTS

	Cogeneration Revenue ($ 000)	Heat Value ($ 000)	Fuel Cost ($ 000)	O & M Cost ($ 000)	Net Savings ($ 000)	Pre-tax IRR (%)	Post-tax IRR (%)
1988	2657	1356	2236	108	1669	0	0
1989	2817	1410	2326	112	1789	0	0
1990	2986	1467	2419	117	1917	0	0
1991	3165	1526	2515	121	2054	9.5	5.2
1992	3355	1587	2616	126	2199	15.6	12.5
1993	3556	1650	2720	131	2354	19.7	17.3
1994	3769	1716	2829	137	2520	22.5	20.7
1995	3996	1785	2942	142	2696	24.5	23.1
1996	4235	1856	3060	148	2883	26.0	24.8
1997	4489	1930	3183	154	3083	27.0	26.1
1998	4759	2008	3310	160	3296	27.8	27.0
1999	5044	2088	3442	166	3524	28.5	27.7
2000	5346	2171	3580	173	3765	28.9	28.3
2001	5668	2258	3723	180	4023	29.3	28.7
2002	6008	2349	3872	187	4297	29.6	29.0
TOTAL	61850	27157	44773	2162	42069		

SOURCE: Canadian Energy Research Institute, January 1987.

Heat Value

In the financial evaluation program employed for this analysis, a credit is awarded to the cogeneration installation for the value of the thermal energy produced. Thermal energy is valued at the cost of fuel to the facility, on a Btu-adjusted basis. In many cases, the installation of a turbine is an add-on to an existing boiler facility. As such, a thermal energy credit may not be applied to the installation of the turbine.

Elimination of a credit for the thermal energy produced causes a substantial deterioration in the financial profile of the cogeneration facility being examined. Before-tax IRR falls from 29.6 percent to 10.3 percent; after-tax IRR declines from 29 percent to 3.5 percent.

The impact in this case is likely overstated. The capital expenditure required for addition of a turbine to an existing boiler facility would be significantly less than that required for the integrated facility being analyzed. A portion of the operation and maintenance expenses would also be applied to the existing boiler system. However, the results of this sensitivity case do indicate the importance of the thermal energy produced to the financial feasibility of cogeneration technology.

Capital Costs

A potential risk in implementation of a cogeneration facility is the possibility of cost over-runs in construction. To investigate this, the evaluation program was run under the assumption of 10 percent and 20 percent increases in capital costs. The financial profile is fairly robust regarding capital costs. Under the 20 percent cost overrun scenario, before- and after-tax IRR decline to 25.9 percent and 22.9 percent respectively. The after-tax IRR result is aided considerably by the accelerated capital cost allowance applied to the higher front-end capital cost.

Class 34 Depreciation

The importance of the accelerated capital cost allowance schedule to the financial feasibility of the cogeneration facility was tested by eliminating the Class 34 schedule from the calculation of after-tax IRR. The resulting after-tax IRR at end of service life is 18.5 percent, a decline of over one-third from the base case. The

importance of Class 34 depreciation is, however, limited to those enterprises in a financial position which allows them to take advantage of this tax provision.

In some respects, the hypothetical cogeneration facility analyzed above represents a "best-case" scenario. The facility benefits from relatively low per-kW capacity costs. A facility of 5 MW would carry a higher per-kW capacity cost in the range of $650-800; units under 1 MW could cost considerably more.

The results of the financial analysis also benefit from the use of 1987 natural gas prices, which have fallen considerably under the natural gas deregulation initiatives of 1985 and 1986. The long-term availability of natural gas fuel at current prices is a critical assumption in the financial evaluation discussed above.

It should be noted that financial criteria are not the only factors which will determine the actual decision with respect to cogeneration investment. Even for a relatively energy-intensive industry, cogeneration may be assigned a low priority compared to, for example, plant expansion or other plant improvements. The reason is that capital expenditures on cogeneration may be perceived as being secondary to the primary business of product manufacturing. In general, the decision whether or not to invest could depend on various considerations, including financial soundness, capital constraints, competing investments, and management attitudes.

Footnotes

[1]Ontario Hydro is in the process of actively marketing steam from its nuclear and coal-fired generating stations. For example, steam from the Bruce Nuclear Power Development on Lake Huron is presently being used to heat local greenhouses. The utility has proposed a large-scale industrial and agricultural park for the area, to serve such industries as food processing and distilleries.

[2]The Point Tupper facility is no longer operating, as a result of the closure of Atomic Energy of Canada Limited's (AECL) heavy water plant. Glace Bay is in operation, although steam is no longer being sold to AECL.

[3]The estimated heat rates and electricity-to-steam ratios are taken from U.S. Congress, Office of Technology Assessment, Industrial Cogeneration in Ontario, Report Prepared for the Ontario Ministry of Energy (Toronto: Cogeneration Associates Limited, October 1980), p.17.

[4]S. David Hu, Cogeneration (Reston, Virginia: Reston Publishing, 1985), p. 34.

[5]Data from Dow Chemical on the Fort Saskatchewan power plant registered annual availability factors of between 92 and 97 percent for the years 1980 through 1985.

[6]These capital cost estimates include the costs of all related cogeneration equipment, i.e., the turbine-generator, boiler, and auxiliaries. Since costs are highly site-specific, the estimates are intended only to give a range of 'typical' expenditures for installation. The data have been obtained through contacts at Ontario Hydro and Dow Chemical Canada Ltd. and are derived from various sources--for example, U.S. cogeneration literature and equipment manufacturers in Canada.

[7]When coal is burned in a fluidized bed combustor, most of the resulting sulphur is trapped in the limestone particulate rather than being emitted through the stack.

[8]The industrial plant will likely experience some downtime during the year, at the mimimum a short period (e.g., 2 weeks) for scheduled annual maintenance.

[9]Note that average cost may actually exceed the marginal costs of supply over the short term, if there is significant surplus capacity in the system. In this case, marginal capacity costs would be zero or negligible, and only the marginal production (i.e., operating) cost would be relevant. Over the long term, however, the marginal supply price is more likely to be the full capital and oeprating cost of a new base load generating plant.

[10]In the United States, the "PURPA machine" controversy refers to cogeneration facilities whose feasibility has been determined solely by the high price (utility avoided cost) applied to surplus power. Recently, however, this environment has been changing with the drop in world oil prices and utility excess capacity (see Chapter 3). In Canada, buyback rates have traditionally been lower than both utility avoided costs and retail industrial rates (see Chapter 4). Some critics argue that low buyback rates have effectively discouraged cogeneration development in this country.

[11]There will also be a natural deterioration in the capacity factor through time as equipment ages and experiences fouling. In performing economic evaluations, it is common to assume a constant capacity factor based on new and clean equipment, operating at its design capacity for most of the year. In fact, it may be more realistic to assume partial loading of the facility and to factor in a gradual decline in performance due to aging. "Cogeneration: System Equipment Options," Power, April 1986, p. S-3.

[12]Capital investment required for the project and other technical specifications for the particular facility are taken from A. Juchymenko, "Utility Policies Towards Customer Owned Generating Facilities," a report prepared by Cogeneration Associates Limited for the Canadian Electrical Association, Contract No. 416 U 465 (Montreal: CEA, October 1985), Appendix A.

Chapter 3

THE U.S. EXPERIENCE

3.1 Development of Cogeneration*

The application of cogeneration technologies has a long history in the United States. At the turn of the century, virtually all industrial electricity demand was met through customer-owned generating facilities, with roughly one-half of that being sourced from cogeneration. At that time, electric utility service had limited availability, was generally unreliable, and was more expensive than self-generated electricity.

In the 1920s and 1930s, federal and state regulation of the electric utility industry led to the elimination of unproductive competition among the utilities and promoted the consolidation and extension of utility service areas. The coincident growth in availability of inexpensive feedstock fuels (coal, oil and natural gas) and technology advances designed to maximize economies of scale in electricity production made centrally-generated electricity an extremely inexpensive commodity. The combination of enhanced reliability and availability of centrally-generated electricity and declining average electricity production costs led to a gradual decline in the relative importance of self-generated electricity. By 1950, the industrial share of electricity had fallen to 15 percent of total electricity generation and by the mid-1970s it had fallen to only 4 percent.[1]

A number of other factors contributed to the decline of cogeneration in the United States. Industry was hesitant to invest in cogeneration applications which involved the production and sale of surplus power, because of the possibility of federal and state regulation as a utility and because of the related reporting requirements.

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*Much of the material in this chapter is based on a research report entitled U.S. Cogeneration Experience, authored by Synergic Resources Corporation for the Canadian Energy Research Institute in September, 1986.

Utilities were most often unwilling, and under no obligation, to interconnect with industrial generation facilities, leaving firms exposed in the event of unscheduled shutdown of the cogeneration facility. Where interconnection was in place, utilities offered very low rates for purchased power, which weakened the economic and financial feasibility of cogeneration. Conversely, utilities tended to charge relatively high rates for standby or supplementary power required by the cogenerator.

The renaissance in cogeneration development in the 1980s can be traced to the response of the federal government to the rising cost of fossil fuels in the 1970s, the growing dependence of the United States economy on imported oil, the spectre of a possible Middle East crude oil embargo and resulting implications for national security of energy supply, and the perception of cogeneration and small-scale generation facilities as "clean" and efficient alternatives to large coal-fired generating stations. In 1978 the Carter Administration passed the National Energy Act (NEA), a comprehensive package of legislation designed to develop and encourage the use of indigenous energy supplies. The component of the NEA of relevance to the electric utility industry was the Public Utility Regulatory Policies Act (PURPA). While PURPA addressed a wide range of electric utility issues, Section 210 of the Act was addressed specifically to electricity production by cogenerators and small power producers.

Section 210 of PURPA directed the Federal Energy Regulatory Commission (FERC) to establish rules that would enforce the following basic principles:[2]

- That cogenerators or small power producers (together referred to as qualifying facilities) be exempt from regulation under the Federal Power Act, the Public Utility Holding Company Act, and any state regulations related to rates and financial reporting;
- Utilities must purchase all power that qualifying facilities make available for sale;
- Purchase rates offered by the utilities should be based on "avoided costs," that is, the costs which the utility can avoid by purchasing energy and/or capacity from a cogenerator, rather than providing it from within the utility's generation system; and
- The rates charged by a utility to a qualifying facility for standby or backup power must be non-discriminatory.

To obtain qualifying facility status under PURPA, and to thereby qualify for the considerable benefits embodied in the legislation, a cogeneration facility was required to meet three qualification standards set out by FERC regarding ownership, operations, and efficiency of fuel use. The qualification procedure is described in Figure 3.1. The ownership standard specifies that electric utilities not own more than 50 percent of a qualifying facility. More specifically, the facility must be owned by a person or company not primarily engaged in the generation or sale of electric power, other than that generated by a cogeneration facility. The operating standard applies only to topping-cycle cogeneration technologies, and specifies that the useful thermal energy output of the facility must be at least 5 percent of the total energy output in any calendar year. Finally, the efficiency standard, which applies only to facilities using natural gas or oil as a fuel, specifies that: (i) for topping-cycle facilities, the useful electric power output plus one-half of the useful thermal output produced in a calendar year must be at least 42.5 percent of the total energy input of natural gas or oil, and at least 45 percent if the useful thermal energy represents less than 15 percent of the facility's total energy output; and (ii) for bottoming-cycle facilities, the useful electric output must be at least 45 percent of the energy input of the natural gas or oil used in the facility.[3]

As is the case with any new legislation, PURPA underwent an extended period of challenges, both through FERC and through the court system. The majority of challenges related to the principles described above: the definition of a qualifying facility and, in particular, the restrictions placed on ownership of a qualifying facility; and to the issues of utility/cogeneration interconnection and calculation of avoided cost-based purchase rates. The new legislation survived these challenges essentially intact and thereby opened the door to a "new" market for industrial, commercial, and institutional entities and third parties, to construct and operate qualifying cogeneration facilities.

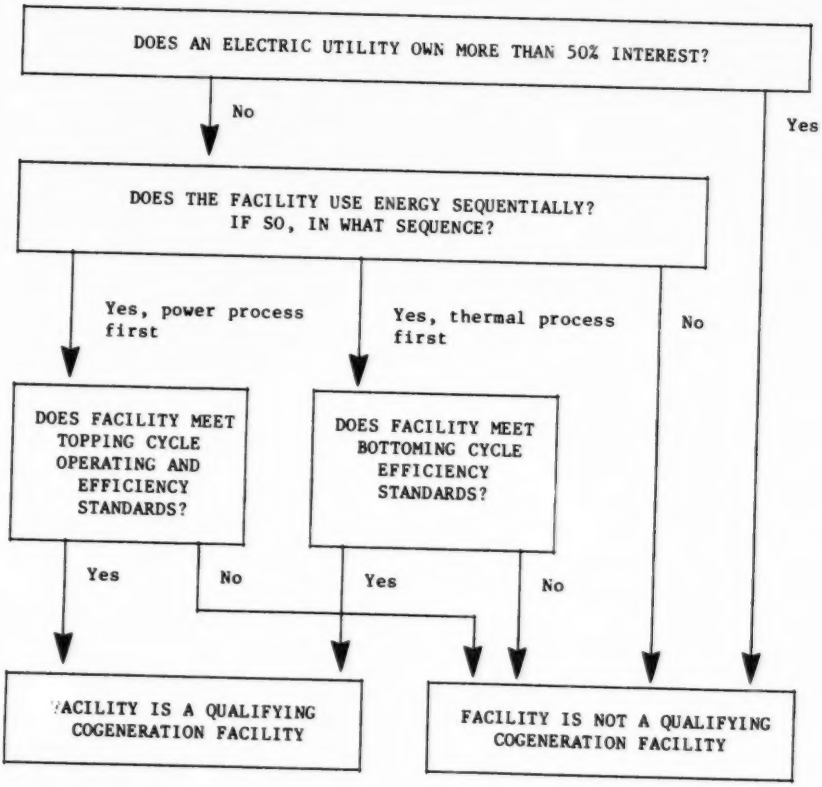
3.2 Current Status of Cogeneration in the U.S.

3.2.1 Existing Capacity

Quantifying the amount of existing cogeneration capacity is a complicated task. The filing for qualifying facility status under PURPA with FERC provides one source of data on likely cogeneration capacity. According to the FERC list of qualifying facilities, there

FIGURE 3.1

REQUIREMENTS FOR QUALIFYING FACILITY STATUS UNDER PURPA


DOES AN ELECTRIC UTILITY OWN MORE THAN 50% INTEREST?
No
Yes
DOES THE FACILITY USE ENERGY SEQUENTIALLY? IF SO, IN WHAT SEQUENCE?
Yes, power process first
Yes, thermal process first
No
DOES FACILITY MEET TOPPING CYCLE OPERATING AND EFFICIENCY STANDARDS?
DOES FACILITY MEET BOTTOMING CYCLE EFFICIENCY STANDARDS?
Yes
No
Yes
No
FACILITY IS A QUALIFYING COGENERATION FACILITY
FACILITY IS NOT A QUALIFYING COGENERATION FACILITY

SOURCE: David S. Hu, Cogeneration, P. 179.

were roughly 24 500 MW of qualifying cogeneration capacity in the United States in January 1986 (see Table 3.1). This figure is likely overstated as a measure of actual capacity, since facilities that have filed for qualifying facility status may not in fact be operating. Application for qualifying facility status is usually made early in the planning process in order to identify the applicability of PURPA benefits to the project being considered. Approval of status may not, therefore, imply construction of the facility.

The International Cogeneration Society (ICS) in Washington, D.C. maintains an independent database of U.S. cogeneration capacity. The current ICS capacity estimate totals 22 000 MW from 712 facilities.[4] Again, this total reflects facilities that have received qualifying facility status under the FERC guidelines. For a variety of reasons, a number of these facilities may not in fact be constructed. In California, for example, difficulties in meeting environmental emission standards for NOx emmissions of 2.5 parts per million or less have delayed the construction of many facilities which received qualifying status under the FERC guidelines.

Of the 719 projects that applied for qualifying facility status in 1985, only 124 had reached a point beyond signing of a contract by early 1986. There 124 facilities represented a total of 3683 MW or about one-third of the total capacity filed in 1985. The discrepancy between the number of facilities which have received qualifying facility status and the number of facilities actually constructed introduces an additional element of uncertainty into the system capacity planning process of the utilities, which must treat qualified facilities as likely sources of electric power to the system grid.

A study by Synergic Resources Corporation in 1982 determined that, at the end of 1982, there were approximately 18 947 MW of "Known" or "Probable" cogeneration capacity in the United States.[5] If we assume that one-half of the capacity filed with FERC and approved over the 1982-1985 period has in fact been constructed (i.e., 2876 MW of the total filed capacity of 5752 MW), we arrive at a conservative estimate of U.S. cogeneration capacity totalling 21 823 MW in 1986.

The industrial sector is the dominant player in the U.S. cogeneration market, due to its large thermal requirements and relatively easy access to financial capital. The most energy-intensive industries, those with the most to gain from reducing thermal and electricity operating costs, account for the majority of existing U.S.

TABLE 3.1

QUALIFYING COGENERATION FACILITIES BY FUEL TYPE

Fuel Type	Capacity Megawatts (number of units)
Natural Gas	14139 (557)
Coal	4906 (102)
Biomass	2312 (109)
Waste	1632 (25)
Fuel Oil	554 (36)
Other	960 (20)
TOTAL	24503 (849)

SOURCE: Federal Energy Regulatory Commission, The Qualifying Facilities Report, 1986.

cogeneration capacity. The greatest concentration of cogeneration is found in the pulp and paper, chemicals, petroleum (e.g., steam flooding of heavy oil fields for enhanced oil recovery applications) and food processing industries. These industries are characterized by significant combustible waste by-products and/or large thermal requirements.

Cogeneration applications in the commercial sector have stepped up considerably over the 1980s, aided by the development of small-scale and customized cogeneration technologies. The driving force in non-industrial cogeneration applications has, however, been the increasing need to dispose of solid waste in an environmentally and economically acceptable manner. Land filling, long the preferred method of solid waste disposal, is environmentally problematic and, due to the growing scarcity of acceptable landfill sites, increasingly uneconomic.

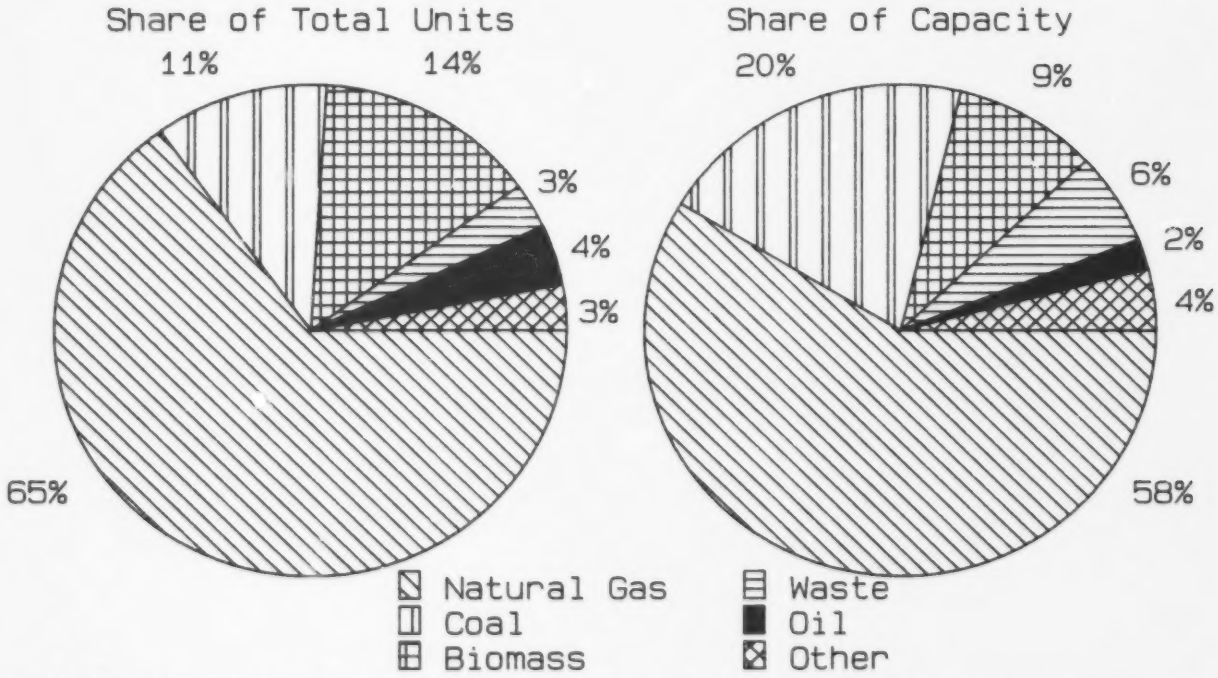
Hospitals and hotels/motels represent a further source of cogeneration potential. The feature of 24 hour-a-day operation provides substantial potential for savings through reduced dependence on purchased electricity. This feature is also prompting considerable interest in cogeneration from universities, colleges and other public or quasi-public institutions.

3.2.2 Capacity by Fuel Type

As shown in Figure 3.2, natural gas is the dominant fuel type for cogeneration facilities. Roughly 65 percent of qualifying facilities are natural gas-based technologies, representing 58 percent of total capacity. Although coal is a less expensive fuel on a Btu-equivalence basis, gas turbine cogeneration cycles tend to be more economic because of the relatively large capital, operating and maintenance costs associated with a coal-fired back pressure or extraction condensing plant. Coal-fired systems also tend to be larger, in order to accommodate economically the higher fuel storage and operating costs. This accounts for the discrepancy between shares of facilities and shares of capacity for gas- and coal-fired systems shown in Figure 3.2. Oil-fired cogeneration capacity accounts for only 2 percent of total filed capacity, in keeping with the objective of the NEA and PURPA legislation, and is not expected to gain in share despite the recent decine in crude oil prices.

Energy cogenerated by resource recovery facilities (i.e., biomass and energy-from-waste) represents 15 percent of total cogeneration

FIGURE 3.2
QUALIFYING FACILITIES BY FUEL TYPE
FERC FILINGS, 1986



SOURCE: Synergic Resources Corporation, U.S. Cogeneration Experience, September 1986.

capacity on file with FERC and is expected to grow considerably over the next 10 years. Urban centers in particular are assessing cogeneration technologies as a cost-effective way of dealing with the problem of solid waste disposal.

The utilization of natural gas as a cogeneration fuel varies widely across the states. As shown in Table 3.2, natural gas is the dominant fuel in only two regions: West South Central, accounting for 82 percent of total capacity; and the Pacific region, accounting for 64 percent of total capacity. However, these regions contain over one-half of the total cogeneration capacity in the United States. Not surprisingly, cogeneration facilities in the New England and East Central regions are among the lowest users of natural gas, reflecting the relatively high cost of natural gas delivered to these areas. Continued gas-on-gas competition in the United States and the expected growth in Canadian gas exports into these regions should, however, provide a significant stimulus for adoption of gas-fired cogeneration technologies.

3.2.3 Potential Cogeneration Development

Estimates of cogeneration capacity to the year 2000 range from 25 000 MW to over 50 000 MW. Table 3.3 provides a summary of nine forecasts of cogeneration capacity, with a mean forecast value of 41 700 MW in the year 2000. The projections provided by Synergic Resources Corporation in Table 3.4 are indicative of expectations for growth across industry groups. In particular, significant capacity growth is expected in the chemicals and petroleum industries, institutions, hospitals, hotels/motels, and municipal solid waste systems.

The realization of this potential is dependent on a number of factors. Key among these are trends in electric utility purchase rates, interpretation and implementation of the PURPA principles, tax legislation, and availability of financing.

3.3 Key Issues and Concerns

3.3.1 Legal Challenges

As is the case with most innovative legislation, PURPA has been challenged in the state courts, the federal courts, and before the state public utility commissions (whose task it has been to set up state rules, using FERC guidelines, for the implementation of PURPA

TABLE 3.2

TOTAL AND GAS-FIRED COGENERATION CAPACITY
BY CENSUS REGION

Census Region	All fuels (MW)	Gas Only (MW)	Gas Capacity/ Total Capacity (%)
New England	2450	117	5
Middle Atlantic	3798	838	22
South Atlantic	5028	335	6
East North Central	4647	247	5
East South Central	1320	115	8
West North Central	1001	297	29
West South Central	15067	12473	82
Mountain	1495	492	32
Pacific	7484	3604	64

SOURCE: Bruce McDowell, "Natural Gas Systems," Public Utilities Fortnightly, June 16, 1984.

TABLE 3.3

U.S. COGENERATION CAPACITY FORECASTS BY VARIOUS SOURCES
(megawatts)

	1990	1995	2000
U.S. Dept. of Energy	--	--	39350
Electric Power Research Institute	27200	--	36600
Frost & Sullivan	20000	25000	31000
Gas Research Institute	28900	--	45600
General Electric	--	--	39000
Synergic Resources	--	--	35000
Dun & Bradstreet - DOE	--	--	47435
TOPS - DOE	--	--	52000
International Cogeneration Society	--	--	50000
MEAN ESTIMATE			41700

SOURCE: Synergic Resources Corporation, U.S. Cogeneration Experience, September 1986.

TABLE 3.4

PROJECTIONS OF COGENERATION POTENTIAL
(1985-2000)

Market	Potential (megawatts)
Industrial	
Pulp & Paper	1500-3000
Petroleum	1000-3000
Chemical	4000-8000
Food	1000-3000
Textile	500-1500
Rubber/Plastics	200- 500
Steel/Metals	200- 500
Lumber/Wood	500-1000
Cement/Glass	200- 500
Metals Fabrication	500-2000
Other Industries	500-1000
Commercial	
Hospitals	200-1000
Hotel/Motel	100-4000
Restaurants	50- 500
Universities	500-2000
Institutions	200-2000
Other Commercial	200-1500
Other	
MSW Systems	2000-8000
Wood/Waste SPF	1000-3500
Industrial Parks	500-3000
Military Bases	200-2000

SOURCE: Synergic Resources Corporation, U.S. Cogeneration Experience, September 1986.

policies). Federal court cases in Mississippi (which ruled PURPA unconstitutional) and in the D.C. Court of Appeals (which asked FERC to reconsider the 100 percent avoided cost rule for utility power purchases and the requirement that utilities interconnect with a qualifying facility) created considerable uncertainty regarding the implementation of PURPA. However, these rulings were appealed to the U.S. Supreme Court which upheld both the PURPA legislation and the FERC implementation rules.[6] While these latter rulings served to clarify the status and constitutionality of the PURPA legislation, a number of implementation issues remain controversial.

3.3.1.1 Utility Ownership of Cogeneration Facilities

The statute, as interpreted by FERC regulations, prohibits electric utilities, electric utility holding companies and subsidiaries of electric utilities from owning more than 50 percent of the equity interest in a qualifying cogeneration facility. The "equity" qualifier limits a utility's share of profits but not of contributing capital. The exclusion of majority ownership by utilities was justified on the basis of concerns that utility endeavors into cogeneration could introduce an anti-competitive element into the field.

Controversy over this issue has centered on whether granting utilities the ability to hold majority interest in qualifying facilities would help or hinder cogeneration development. Allowing majority ownership by utilities could potentially enhance the expansion of cogeneration applications for a number of reasons.[7] First, utilities are in the business of electricity generation and, presumably, could introduce the new technology in the most economic and system-efficient manner. Second, utilities tend to have less stringent payback period requirements, and may have access to lower cost capital, which allows for the consideration of otherwise marginal applications. Third, active displacement of utility fossil-fired generation with utility-owned cogeneration capacity could reap significant emission-offset benefits. Finally, where cogeneration potential exists, utilities could benefit from development of new markets. Under the current legislation, utilities are instead facing potential declines in industrial and commercial load from customers considering on-site cogeneration development.

Several utility-backed bills have been introduced in Congress since 1978 calling for relaxation of the ownership restrictions. Most

of these have been rejected. In the most well-known case, the investment banking firm of Kidder-Peabody proposed allowing utilities to own qualifying facilities through a diversified portfolio of indirect limited partnership interests. Under the proposal, utilities would not exercise control over project operation or decision-making, although more than 50 percent of project benefits would flow to the utility. The FERC rejected Kidder-Peabody's argument that "ownership" be interpreted as "control" and not "equity interest."[8]

Challenges on this issue are likely to continue, particularly those designed to back-in utility involvement in this potentially lucrative and competitive generation technology. However, unless substantial evidence can be provided to the contrary, it is likely that FERC will continue to favour cogeneration development through independent, private sector initiative rather than utility control.

3.3.1.2 Backup Power

Current FERC guidelines state that, under third-party ownership arrangements, only those entities that actually own and operate a facility (rather than those who lease it) are entitled to backup services under PURPA. Backup power is defined as power bought by the cogenerator from a utility for use when the cogeneration facility experiences an unscheduled outage. The implication of this guideline is that the third-party (which owns and operates the facility) would be deemed a "public utility" under Section 3(22) of the Federal Power Act, should it have to purchase backup power from the utility and resell it to the company actually utilizing the facility. Since a public utility cannot own more than 50 percent of a qualifying facility, the third-party financed system would also lose its qualifying facility status.

On this matter, individual states are free to reach their own conclusions and, in most cases, are apparently not following the FERC precedent. In those states where Public Utility Commission (PUC) support for cogeneration development is not strong, however, this precedent could have significant negative implications for third-party financing arrangements.

3.3.1.3 Wheeling

PURPA requires a utility to purchase power from any qualifying facility, regardless of its location, but does not require a utility to

wheel power on behalf of the cogenerator or its customers. Because the avoided costs of a distant utility may be comparatively high, the cogenerator may attempt to arrange to sell power to the distant utility by having the local utility wheel the power (i.e., transmit the power over its system without distributing it to its customers). The issue pits the economic efficiency associated with more competitive markets against the potentially adverse impacts that wheeling may have on the wheeling utility's customers and against the utility's status as a common carrier. In the one case decided thus far, FERC rejected a request for wheeling because it would have resulted in a loss of sales by the wheeling utility.

To date, at least eleven states have adopted legislation giving utilities the mandate to wheel power from qualifying facilities. The rulings include comprehensive wheeling obligations, requirements to wheel power when possible or practical, and provisions for the relevant PUC to rule on a case-by-case basis, ordering wheeling only in the absence of adverse consequences for the host utility.

3.3.2 Calculation of Avoided Costs

As mentioned in Section 3.1, the FERC guidelines requiring utility interconnection with a qualifying facility and purchase of power at the utility's avoided cost of generation have been challenged and upheld in the federal courts. The calculation of avoided cost, however, has proven to be a difficult process. For the most part, FERC has handed the responsibility for determination of avoided cost to the individual state PUCs. The PUCs, in turn, have intervened in the determination process to varying degrees, depending largely on the degree of support on the part of individual PUCs for the development of cogeneration within their jurisdictions. In general, the PUCs are required to:[9]

- set standard purchase rates for small cogeneration facilities (usually defined as less than 100 kilowatt capacity);
- set a method of purchase from larger facilities;
- set rates and/or the means of sale of supplementary, backup, maintenance, and interruptible power to the cogenerator; and

- establish data filing requirements to allow the cogenerator to verify the calculation of avoided cost-based purchase rates.

In theory, avoided cost rates should be based on an assessment of utility operating and capital costs before and after the purchase of power from a qualifying facility. The difference is then pro-rated to all facilities providing power to the utility. This requires the PUC to deal with issues such as the relative value of peak and off-peak power, the reliability of cogeneration capacity, the relative value of long-term versus interruptible power, and so on. The interest of the individual PUCs in cogeneration development and the ability to deal with these complicated issues have been major factors in the determination of the energy and capacity credits comprising the avoided cost calculation.

3.3.2.1 Energy Credit

A number of methodologies have been employed in calculating the energy component of standard utility purchase rates. The most common is the incremental heat rate approach. The heat rate of a given increment of system load is estimated and multiplied by the cost of the fuel required to produce these BTUs. This allows purchase rates to vary according to the type of capacity being utilized by the utility at a given point in time. For example, purchase rates would be higher when inefficient older plants are being utilized than when only modern baseload facilities are being used.

A variation of the above would be to base purchase rates on the actual running costs of the utility at any given point in time. Alternatively, the estimated cost of the most common fuel used by the utility (California PUC) or the historical average fossil fuel cost (Connecticut District PUC) have been employed as a proxy for the energy credit.

A third approach is to specify a generating unit for use in calculating avoided energy costs (New Hampshire PUC). Finally, a number of PUCs have chosen to use the energy component of power purchased by a utility from a pool as a proxy for avoided costs (Iowa, New Jersey). This approach has been adopted by most states containing nongenerating utilities.

3.3.2.2 Capacity Credit

The FERC guidelines provide for payment of a capacity credit in the avoided cost calculation only if a utility has need for new capacity. This has introduced a further series of complications, including the definition of capacity need (e.g., time horizon for determination of need) and prerequisites for a cogenerator to be considered utility capacity (e.g., provision of firm power, reliability of the facility, length of purchase contract, and so on).

A number of approaches have been utilized in arriving at a capacity credit measure. The most common is to specify a generating unit for calculating a capacity payment. The choice of unit (e.g., fossil fuel-fired peaking unit versus more expensive base-load plants) often reflects the degree of support for cogeneration by a given PUC. A second approach is to price the capacity credit at the cost of capacity bought from a pool, or from another utility. The most sophisticated approach is the differential revenue requirement method. Under this method, the utility determines its optimal system expansion plan (usually over a 15-20 year time horizon) with and without expected cogeneration interconnections. The difference in system capital costs represents the avoided capacity cost due to existence of cogeneration facilities on the system. Clearly, few utilities possess the sophisticated modelling tools or human resources required for this calculation. In addition, the results are critically dependent on the accuracy of long-term forecasting methodologies, with the likelihood of significant miscalculations and, as a result, the provision of incorrect signals regarding the need for incremental system capacity.

The absence of more concise FERC guidelines on calculation of avoided cost has resulted in a greater variation in utility purchase rates than would be warranted by differences in generation technologies alone. This variance in avoided cost calculations in turn aggravates the issue of wheeling of power to utilities offering the highest purchase rates. On the other hand, the freedom in purchase rate determination has allowed certain PUCs (i.e., California) to more aggressively pursue a pro-cogeneration policy stance.

3.3.2.3 Market-Determined Purchase Rates

The inherent difficulty in calculation of avoided cost rates, together with the objective in many jurisdictions of actively promoting

cogeneration development, has resulted in numerous cases of purchase rates being set in excess of actual avoided cost of power to the relevant utility. Purchase rates in excess of the purchasing utility's full avoided costs can arise from a number of sources, including:

- Failing to properly distinguish between "sunk costs" and "avoidable costs" in determining purchase rates;
- Requiring utilities to include capacity payments in qualifying facility purchase rates, even when the utility has excess capacity and no measureable savings would result from such purchases;
- Making "incentive" payments to qualifying facilities, often based on their perceived "intangible" benefits (e.g., environmental emission credits), which aren't directly linked to the utility's avoided cost but are viewed as necessary to encourage cogeneration development; and
- Where there is more cogeneration capacity offered than there is need, allowing qualifying facilities access to avoided cost rates on a first come, first served basis regardless of which facilities are more economically efficient.

A recent study prepared for the U.S. Department of Energy addresses these issues from the standpoint of economic ineffficiencies inherent in the PURPA legislation. Perhaps the most important recommendation of the study is to allow greater reliance on market forces in establishing purchase rates and, more generally, in determining the most economically efficient mix of generating sources.[10]

One possible variation of such a process would be the implementation of a bidding system for access to avoided cost purchase rates by qualifying facilities. Avoided cost ceiling rates would be established in the marketplace, with the result that the most efficient power production facilities would obtain priority in negotiating supply contracts with a utility. This approach would increase economic efficiency while still providing sufficient incentives to encourage cogeneration development since the market-developed purchase price would presumably settle at a level sufficient to provide the "marginal" capacity increment with an adequate (but not excessive) return on investment.

Limited forms of bidding systems to determine purchase rates have been addressed and/or implemented in a number of states (e.g., Massachusetts, California). However, it is not clear that such systems comply with existing FERC regulations regarding PURPA implementation. This is particulary true for systems based on capacity increments or blocks, with a lower purchase rate offered in each subsequent block.[11]

From a broader perspective, while a bidding system to determine access to avoided cost-based purchase rates would enhance economic efficiency, elimination of a number of other elements within the existing FERC regulations regarding PURPA implementation would possibly be of more importance in this regard. These include regulations on size limitations which may cause developers to deliberately undersize small power production facilities, thereby losing economies of scale, in order to retain eligibility for PURPA benefits; prohibitions on fuels used in qualifying facilities, thereby denying eligibility to types of generation (e.g., advanced coal technologies) that may be more economical than those currently granted PURPA benefits; and the absence of more stringent engineering efficiency standards which, if implemented, would maximize the net gain in overall engineering efficiency in the generation of non-system electricity.[12]

3.3.3 Tax Benefits for Cogeneration Projects

Most of the tax benefits available to investors in cogeneration have been implemented since the late 1970s and reflect the governments' supportive stance on development of indigenous energy sources. The tax reform legislation anticipated in early 1987 may, however, lessen the attractiveness of third-party financing of investment in cogeneration. By way of example, the energy tax credit, which provided for a credit of 10 percent of capital invested in a cogeneration project against tax payable in the year of investment, was allowed to expire on December 31, 1985 after a three-year extension to the 1982 expiry date. The investment tax credit, which allows for a further credit of 10 percent of capital expenditures against tax payable for most business projects, is repealed under the proposed tax reform legislation.

The accelerated cost recovery system, which sets guidelines for accelerated depreciation of most cogeneration equipment, is expected to survive the pending tax legislation. However, it appears likely that the period over which the equipment can be depreciated will be

significantly extended, diminishing the benefits derived from the tax incentive.

3.3.4 Financing Options

Financing options available to a firm considering development of a cogeneration facility are largely determined by the credit worthiness of the firm and the economics of the project. The relatively large capital component of a cogeneration facility tends to favour external financing over internal or equity financing. Equity financed projects must compete with the firm's other investment options and are adopted only when the project return at least meets the firm's internal rate of return requirements, given project risk and available tax benefits.

External financing is usually secured on either a recourse basis or a project finance basis. Under recourse financing, the borrower accepts a direct legal obligation to repay the loan, which is in turn secured by some or all of the firm's assets outside of the project itself. This financing arrangement is usually available to large corporations or institutions. Under project financing, the lender has no legal right to the borrower's assets, beyond those incorporated within the cogeneration project itself, should the borrower fail to make payment on the loan. Since the borrower's other assets are not at risk, this type of financing is more difficult to obtain. In general, the project's risk of failure must be relatively low to qualify for project financing. The guidelines provided under PURPA have increased considerably the availability of such financing for cogeneration projects.

Third-party financing, which generally refers to arrangements in which neither the project owner nor the energy user finances the project, has become increasingly popular in cogeneration development. Third-party financing organizations are often willing to accept lower rates of return than could the firm, because they can benefit more from the tax and depreciation benefits available on cogeneration facilities. The availability of such financing has therefore allowed many firms to implement cogeneration projects which would otherwise have been unacceptable on economic and financial grounds.

Although presently prevented from owning more that 50 percent of the equity of a qualifying cogeneration facility, utilities are becoming more interested in financing cogeneration projects. Many are

establishing subsidiaries that can take on financing as one part of their involvement in a project. For many utilities, participation in and promotion of cogeneration development forms one aspect of a more general conservation strategy designed to delay or avoid the construction of expensive, large-scale baseload capacity.

3.4 Summary

The Public Utility Regulatory Policies Act and accompanying FERC implementation guidelines provided a necessary vehicle for the renaissance of cogeneration development in the United States. An appropriate economic environment, characterized by rising fossil fuel prices, declining economies of scale in large scale power generation, and the delay and possible elimination of most of the U.S. nuclear generation capacity, provided the financial stimulus for reconsideration of customer-owned generation facilities. PURPA addressed the problematic issue of utility-industry interface in a manner which reflected the federal government's supportive position on development of indigenous energy sources.

Cogeneration capacity in the United States is expected to more than double by the year 2000, to over 47 000 MW from a current estimated capacity of 21 800 MW. This represents a capacity gain equal to roughly 17 large-scale baseload coal-fired generation facilities. Whether this potential will be realized depends on a number of factors, including trends in fossil fuel prices and electricity rates, availability of financial capital, and the degree of support for cogeneration development exhibited through PUC and utility decisions on implementation of the PURPA guidelines.

Footnotes

[1]Dilip R. Lamaye, "Industrial Cogeneration: Trends and Prospects," SRC Paper No. 906-139 (Bala Cynwyd, Pennsylvania: Synergic Resources Corporation, November 1985).

[2]Synergic Resources Corporation, "U.S. Cogeneration Experience," SRC Report No. 7325-R1, September 1986.

[3]David S. Hu. Cogeneration. (Reston, Virginia: Reston Publishing Company Inc., 1985), P. 180.

[4]Supra, footnote 2, P .4.

[5]Synergic Resources Corporation, Evaluation of Dual Energy Use Systems, EPRI EM-2695, Electric Power Research Institute, Palo Alto, California 1982.

[6]Claire Wooster and Eric Thompson, "How Well are PURPA's Cogeneration Incentives Functioning?," Energy Economics, Policy and Management, Winter 1983-84, P. 43.

[7]Neil J. Numark and Douglas W. Cooper, "Prospects for Utility Ownership of Cogeneration," Public Utilities Fortnightly (February 2, 1984), P. 25.

[8]Supra, footnote 2, P. 25.

[9]Wooster and Thompson, "How Well Are PURPA's Cogeneration Incentives Functioning?," P. 44.

[10]Pfeffer, Lindsay & Associates Inc., Emerging Policy Issues in PURPA Implementation, prepared for U.S. Department of Energy, Contract No. PEAC01-83-PE-70404, March 1986, P. 13-14.

[11]Note that in a true market-determined system with one buyer and many sellers, rates in each capacity block would in fact be higher than in the preceding block, thereby maximizing the utility (and ratepayer) gains from development of the most efficient facilities first. Such a system would likely be disallowed under existing regulations. A declining-rate capacity block system combined with a competitive cost criterion would be the most effective system from an economic efficiency standpoint.

[12]Grahame, T. J., "Cogeneration and Renewable Resources: How Can They Best Contribute to Economic Electrical Generation?", U.S. Department of Energy, October 1986, P. 3-4.

Chapter 4

THE CANADIAN EXPERIENCE

4.1 Introduction

The absence of historical data regarding cogeneration capacity and power production makes it difficult to assess the history of cogeneration development in Canada. In general, the development of industrial electric power generation in Canada has paralleled that of the United States, with two major exceptions. First, hydroelectric generation has played a much larger role in industrial electricity generation in Canada than in the United States. As shown in Table 4.1, hydroelectric generation accounted for over 80 percent of total industrial electric generation in 1977. The dominance of hydroelectric generation is particularly prominent in Quebec and British Columbia (see Table 4.2).

Second, industrial electricity generation in Canada has benefited from accommodative interconnection and standby policies on the part of most utilities, relative to the situation in the United States prior to the implementation of the PURPA legislation. These policies, where applicable, were developed on a voluntary basis by the electric utilities and removed a major roadblock to the use of customer owned generation facilities. Such policies were essentially nonexistent in the United States prior to the implementation of the PURPA legislation.

Only a minority of utilities in Canada have in place policies that allow for the sale of surplus power to the utility grid. For the most part, however, industrial electricity generation has been developed specifically to meet the on-site power requirements of individual companies. Sale of surplus power to a utility grid has been the exception, rather than the motivating factor behind such developments.

As shown in Table 4.1, growth in aggregate industrial electricity generation over the past decade has been negligible. Internal combustion generation has fallen off markedly since the mid-1970s, due partly to the rapid rise in oil prices over the late 1970s and forecasts of continued price increases through the 1980s, and partly to the

TABLE 4.1

INDUSTRIAL ELECTRICITY GENERATION IN CANADA[a]
(gigawatt-hours)

	Hydro-Electric	Conventional Steam	Gas Turbine	Internal Combustion	Total	Share of Total Electricity Generation
1977	30583	4955	1054	384	36976	11.7
1978	31597	5357	1191	293	38438	11.5
1979	27618	6059	1349	306	35332	10.0
1980	30651	6008	1427	184	38270	10.4
1981	31323	5492	1409	134	38358	10.1
1982	29281	5842	1988	117	37228	9.9
1983	30004	6059	1886	93	38042	9.6
1984	29697	5979	1866	67	37609	8.9
1985	29661	6120	1911	78	37770	8.5
1986 (E)	29269	5967	2105	70	37441	8.2

SOURCE: Statistics Canada, Catalogue No. 57-001

[a]For companies having at least one plant with a total generating capacity of over 500 kW.

TABLE 4.2

INDUSTRIAL ELECTRICITY GENERATING CAPACITY, BY PROVINCE[a]
(December 31, 1985; megawatts)

	Hydro-Electric	Conventional Steam	Gas Turbine	Internal Combustion	Total
Newfoundland	80	25	0	3	108
Prince Edward Isl.	0	0	0	0	0
Nova Scotia	5	81	0	1	87
New Brunswick	17	137	0	0	154
Quebec	2574	38	0	8	2620
Ontario	309	336	181	0	826
Manitoba	0	27	0	4	31
Saskatchewan	23	79	0	1	103
Alberta	0	184	203	11	398
British Columbia	1309	439	0	29	1777
Canada - Total	4317	1346	384	57	6104

SOURCE: Statistics Canada, Catalogue No. 57-206

[a]For companies having at least one plant with a total generating capacity of over 500 kW.

promotion of off-oil conversion by the federal government. While hydroelectric and steam turbine generation have remained stagnant over the period, gas turbine generation has virtually doubled since the mid-1970s. This increase can be attributed largely to the adoption of cogeneration technology. According to Statistics Canada data, which cover only those installations with generating capacity of over 500 kW, gas turbine generating capacity is located exclusively in Ontario and Alberta. This would encompass large installations associated with chemical and refining/petrochemical activities in these provinces.

The lack of industrial electricity generation development in Canada over the 1980s marks a major departure from the United States, where implementation of the PURPA legislation has provided a sharp stimulus to cogeneration and small power production. Government and utility policies in Canada have remained considerably less supportive of such developments.

4.2 Government Policies Towards Cogeneration

Canada does not have in place a national policy with regard to the development of industrial cogeneration; nor is there any comprehensive legislation similar to PURPA in the United States. The federal and some provincial governments have indicated their interest in, and support for, cogeneration development. Studies into the commercial and technical potential for cogeneration have been undertaken in various jurisdictions, many under the auspices of federal-provincial funding arrangements in support of provincial resource development. These are discussed further in Section 4.4. However, no provincial government has in place a policy aimed at encouraging the development of cogeneration.

Indeed, the only such policy initiative has been the federal government's decision to allow the application of Class 34 depreciation to cogeneration facilities, effective December 31, 1979. Previously, the construction of a thermal plant was considered to be part of the production process and, hence, generally qualified for a rapid tax write-off of capital costs incurred in construction. However, as soon as a turbine was connected to the plant to generate electricity, the plant came under a utility classification which did not receive as favourable a tax write-off schedule. Class 34 depreciation, which provides for depreciation of eligible capital expenditures over the first three years of the plant life (25% in the first year, 50% in the second year, 25% in the third year), was extended indefinitely on

December 13, 1984.[1] Elimination of this incentive would be a serious blow to development of cogeneration in Canada.

The rationale for government policy encouraging cogeneration development stems from an economic, rather than financial, assessment of cogeneration potential. Projects which are not feasible from a purely private sector, financial standpoint may in fact be desirable when viewed in the broader context of a social cost-benefit assessment. Within this framework, sourcing of incremental generation capacity is analyzed taking full acount of the resource costs of electricity from new, conventional supply projects. Assessment of fuel efficiencies and generation of surplus power from cogeneration installations valued at appropriate shadow prices for electricity and feedstock fuels increases considerably the attractiveness of cogeneration development when viewed from a societal standpoint.

4.3 Utility Policies Towards Cogeneration

Utility policies regarding cogeneration have evolved largely on an ad hoc basis, as individual contracts have been negotiated with prospective cogenerators. As a result, these policies tend to reflect the particular circumstances of the provincial system--for example, generation mix and the extent of surplus capacity. Furthermore, a number of Canadian utilities have had few encounters with cogenerators, so that their policy in this area is not very developed.[2]

Ontario Hydro is among the most advanced Canadian electric utilities in terms of a formalized policy on parallel generation. Its policy is "intended to support Ontario government policies and programs to encourage the development of small scale private generation projects."[3] This support includes providing technical assistance for feasibility studies, purchasing surplus generation, and wheeling power for the parallel generator. In order to increase public awareness, the utility publishes information on its interconnection requirements and purchase policy.[4]

To date, much of the lack of interest in cogeneration has been attributable to low industrial electricity rates and the relatively small amount of customer-generated power. Lately, however, several utilities and provincial governments have been re-examining their policies towards privately-owned generation. Also, there have been a few recent cases of regulatory pressure on utilities to purchase surplus energy from parallel generators.[5]

The following discussion considers two main aspects of utility cogeneration policy: interconnection practices and purchase of surplus power. Aside from industrial retail electricity rates, these are the areas in which the utility exerts a direct influence on cogeneration development. The discussion is based on a number of sources, including a 1984 study for the Canadian Electrical Association (CEA) entitled Utility Policy on Cogeneration and Small Power Production.[6] This study contains a survey of utility policy with respect to interconnection requirements, metering, purchase policy, and other related items.

It should be noted that most utility policies do not make a distinction between cogeneration and other forms of parallel generation. Therefore, the terms are used interchangeably below.

4.3.1 Interconnection Practices

Generally speaking, a cogenerator will probably want to operate in parallel with the electric utility system. This is consistent with a "Priority Thermal" mode of operation, in which the cogenerator buys power from the utility when needed and/or sells power to the utility in times of surplus. As a consequence, interconnection policy can have a considerable impact on the technical and economic feasibility of cogeneration.

Unlike the U.S. (pre-PURPA) case, the right to interconnect has not been a significant stumbling block for prospective cogenerators in Canada. In principal, all of the major electric utilities support the interconnection of customer-owned generating facilities. One utility, B.C. Hydro, will not currently allow hookup to the integrated grid, because of the degree of excess capacity in its system. Existing cogeneration in that province is located at pulp and paper plants which do not generate surplus energy for the grid. These plants function in one of three ways: (1) they are separate from the grid and produce all of their required electricity; (2) they are connected to the grid and isolate that portion of their plant which is used for cogeneration; or (3) where practicable, they are connected to a neighboring municipal utility system. In this latter case, policies and procedures for sale of surplus power to the municipal grid have been established.

4.3.1.1 Interconnection Requirements

In the survey done for the CEA, 67 percent of the utility respondents[7] indicated that they required a contract to be signed by

the cogenerator. A total of 75 percent stated that they had a set of terms and requirements for interconnection. Several utilities that responded in the negative (e.g., B.C. Hydro and Hydro-Quebec) do not have any interconnected cogeneration at the present time.

Typically, the terms and conditions for interconnection relate to utility concerns about safety, production, and quality of service. The underlying concept is that interconnection should not have an adverse effect on the system (harmonics, voltage regulation, etc.), utility employees, or customers. This is usually reflected in technical requirements covering such areas as metering, production, switching and maintenance. The majority of utilities are willing to provide additional metering equipment (i.e., in excess of normal metering service) to measure two-way power flows. As well, most stipulate conditions under which the utility can disconnect a cogenerator in order to ensure quality of service to its other customers.

A cogenerator is generally responsible for interconnection costs over and above the costs of regular service (e.g., for additional switching and protection equipment). In most cases, the cogenerator is also required to sign a statement indemnifying the utility with respect to harm or damage caused by the cogeneration equipment. Some utilities specify liability insurance for the cogenerator of a certain minimum amount.

An example of a utility's interconnection requirements is presented in Appendix A.

4.3.1.2 Wheeling

Some Canadian utilities are willing to provide a wheeling service to parallel generators. A cogenerator, for example, may wish to have his electricity transmitted to a distant company plant, or to other industrial users in the local area. From the utility point of view, wheeling may be acceptable provided that system safety is ensured, that there is adequate transmission capability available, and that all costs and losses are appropriately accounted for.

As a rule, wheeling charges are based on the incremental cost of using the utility transmission network. Ontario Hydro will wheel capacity of 25 kW or more for the customer. Its charges consist of an incremental rate (in ¢/kWh or $/kW/month) plus a monthly administration cost.

4.3.1.3 Standby Power

Standby service is an arrangement whereby the utility agrees to provide backup or emergency power to the parallel generator. It is a form of insurance for the customer to cover his electricity needs during startup, scheduled maintenance, and emergency downtime. The alternative to utility standby power would involve the customer installing his own reserve generating capacity or having access to another external source of power (e.g., another cogenerator).

Charges for standby power may be determined on the basis of a separate fixed charge (in $/kW) per month. This is the normal practice for valuing standby power in the United States, and amounts to a payment for reserved capacity (i.e., regardless of whether or not the power is taken). Alternatively, backup power may be incorporated into the demand charge ratchet of the customer's retail rate. Under the ratchet, the customer is billed according to his peak demand during the month or during some other specified period (e.g., the previous 11 months).

For the utility, the ratchet rate is justified in terms of the continuing cost of transformers and other equipment. However, it has been argued in the past that such rates impose an excessive burden on the industrial customer. The costs can be particularly onerous for customers with loads that fluctuate significantly throughout the year. As a result, there will be an incentive to practice load management and schedule maintenance for the utility's off-peak periods.[8] Some cogenerators, such as Dow Chemical in Sarnia, effectively avoid standby charges by shedding loads when their generating capability is impeded.

In answer to some of these concerns, Ontario Hydro has introduced a new category of standby service for customers in excess of 5 MW. Subject to approval by the utility, "Supplementary Power" may be taken for a fixed daily charge. From the customer's perspective, the use of a daily rate is preferable to monthly charges which may be applied to power used only for a short time period (e.g., a matter of hours).

The following set of principles provide a useful framework within which to establish standby charges to a cogenerator.

- Charges should be negotiated on an individual or case-by-case basis, to reflect the particular characteristics of

the utility (e.g., load profile, generation mix) and the cogenerator (e.g., equipment reliability, scheduled outages).

- Standby charges should reflect the relatively low probability that all parallel generation capacity connected to the grid will experience outages simultaneously in the peak period. Indeed, as additional customer-owned generation is added to the grid, the utility "planning risk" of having to meet that load becomes smaller.

- Firm standby power should include both a capacity charge and an energy charge. If standby service is provided on a non-firm (or "as available") basis, then capacity is not reserved for the cogenerator and only the relevant energy costs should be recovered.

- Ideally, standby charges should be assessed only for the actual time period in which the service is received, in order to minimize pricing inequities.

- To account for the varying costs of providing standby power over time, some form of time-differentiated pricing structure should be employed (where practicable) for peak/off-peak and summer/winter periods.

4.3.2 Purchase Policy

Three-quarters of the utilities in the CEA survey stated that it was not their policy to purchase power from customer-owned generation. Of the remaining utilities, the Saskatchewan Power Corporation does not provide compensation for privately-generated electricity, but does allow the customer's meter to run in reverse for power of up to 15 kW. Hydro-Quebec does not currently have any cogenerators interconnected with its system, and has no firm policy on interconnection and purchase of surplus electricity. However, in discussions with utility representatives, it was indicated that cogeneration is being seriously studied as an option for the post-2000 period.

4.3.2.1 Buyback Rates

In Canada, buyback rates are not determined according to any single governing principle such as the avoided cost rule used under PURPA. Furthermore, no formal process exists for reviewing these rates, or utility avoided costs, in a public forum.[9] Utilities calculate their purchase rates based on a number of different formulae, as shown by the examples in Table 4.3. In some jurisdictions (e.g.,

TABLE 4.3

SELECTED BUYBACK RATES FOR
CUSTOMER-OWNED GENERATION

Utility	Current Rate[a] (cents/kWh)	Formula
Alberta Power	(No interconnected customers)	Percentage of utility incremental fuel cost[b]
City of Calgary Electric System	Net energy billing at retail rate, no credit for surplus	-
Manitoba Hydro	3.278	Run-off rate for farms or residential service
Maritime Electric (P.E.I.)	3.0 - 5.5	Average price of purchased economy energy
N.B. Power	2.404 - 4.139	70% of average incremental cost
Nova Scotia Power	if < 10kW, 3.71 - 6.27 if < 15MW, 2.09 - 2.84 if > 15MW, negotiated	Run-off rate
Ontario Hydro[c]	3.60 if > 65% C.F.[d] 2.54 if < 65% C.F.	85% of bulk rate (= Revenue Requirement/Energy Delivered)
TransAlta Utilities	Net energy billing at retail rate, surplus valued at 1.6	Avoided cost of fuel

SOURCE: TransAlta Utilities Corporation, "Update Synopsis of Utility Policy on Cogeneration and Small Power Production," Table 2, April 1986.

[a]As of April 1986
[b]Rate for Surplus Energy
[c]Standard Energy Rates as of December 31, 1986
[d]Capacity Factor

Saskatchewan and the City of Calgary), allowing the customer's meter to run backwards amounts to a net billing at the industrial retail rate.

If there is a common philosophical thread among the different rate structures, it is that they have been designed to share the savings in production (i.e., fuel) costs resulting from customer-owned generation. In addition, the rates for surplus power have been lower than industrial (retail) electricity rates. Possible justifications for this discrepancy include:

- the excess capacity in provincial systems;
- the "sporadic" nature of customer-owned generation relative to the firm, utility-dispatched resources; and
- utility administrative overhead.

In 1985, Ontario Hydro brought its buyback rate into line with the retail price for large industrial customers.[10] The present standard rate is based on the utility's average wholesale power cost. For 1987, a new 10 year fixed rate of 4.94¢/kWh is available to new cogeneration projects which utilize renewable fuel inputs. This rate includes some accounting for future as well as current generation costs. Ontario Hydro is considering setting rates in the future on the basis of long-term avoided costs.

The following set of principles provide a useful framework within which to establish buyback rates for a cogenerator.

- Rates should be determined through negotiation rather than according to a set rule such as avoided cost. Negotiation can allow for a mutual distribution of the returns and risks of the transaction, and can take account of such factors as the specific load profile and generation mix of the utility, relative reliability of the cogeneration and utility facilities, and long-term availability of the cogeneration facility. In all cases, however, the methodology and calculation of buyback rates should be available for scrutiny and analysis by all parties concerned.
- Where cogenerated power is provided on a firm basis, a capacity charge component should be included in the buyback rate, to reflect the value of the capacity to the utility in both the short- and long-term.
- Where possible, a time-differentiated price system should be adopted to reflect the different value placed on

purchased power by the utility at different times of the year. Ontario Hydro currently has in place an optional winter/summer differentiated pricing structure (see Section 4.3.2.2).

- Generally, buyback rates should be designed to encourage an efficient level of cogeneration development within the utility's system expansion plan. If such a policy yields purchase rates below utility system avoided cost, the cost savings should be appropriated by the utility in order to benefit other utility customers.

4.3.2.2 Capacity Credits

Capacity credits refer to payments to parallel generators for access to firm generating capacity as required by the utility. Currently, two of the major utilities offer capacity credits. The Nova Scotia Power Corporation will negotiate a credit if the generating unit is greater than 15 MVA. Ontario Hydro provides a capacity charge in its optional time-differentiated rate structure:[11]

Winter	$7.30 per (peak period) kW per month
Summer	$3.65 per (peak period) kW per month

This capacity payment is applicable to customer-owned generation of 250 kW or greater, and requires a minimum capacity factor of 65 percent.

4.4 Potential for Cogeneration Development

The assessment of cogeneration potential requires an appraisal of prospective installations from at least three perspectives: financial or commercial feasibility, economic potential, and technical potential.

Financial feasibility involves a private or company-specific assessment of the benefits and costs associated with a prospective installation. These are assessed against the internal hurdle rates (payback period, internal rate of return) established by the firm, based on a forecast of fuel costs, electricity prices, operating costs, and so on, over the expected service life of the installation. Prospective installations which are financially feasible would presumably be pursued by the firm, subject to internal priorities regarding competing projects and availability of investment capital.

Economic potential is determined on the basis of an assessment undertaken from the point of view of society as a whole, comparing the options of sourcing incremental generation capacity either by cogenerating or from the existing electric utilities. If it is cheaper to source the capacity through cogeneration rather than through the utility (based on an assessment of all the direct, and possibly indirect, production costs of electric power generation), then a "social saving" would result and the cogeneration project would be deemed to be economically viable. Within such as assessment, for example, a cogeneration facility could be awarded additional credits if, as a result of the installation being located near a load centre, losses incurred in transmission (or the cost of constructing transmission facilities) under utility provision of electric power could be reduced or avoided. Greater efficiency of fuel use would also favour the cogeneration facility, with the fuel savings valued at full social cost (or shadow price) rather than private costs. It should be noted that a project which is economically feasible may not be financially feasible. In such a case, the firm would require some form of subsidy or incentive in order to undertake the project.

Finally, an assessment of technical potential would require the study and identification of those sites having the physical or technological capability to produce cogenerated electricity, for all candidate cogeneration technologies. This would entail, at a minimum, an assessment of the site and thermal load characteristics of all companies operating boiler plants at all sites.

An independent assessment of industrial cogeneration potential in Canada is outside the scope of the current study. A number of studies have been undertaken in particular jurisdictions or on particular technologies which provide an indication of likely potential. These are discussed in the following section.

4.4.1 Steam Turbine Cogeneration

Energy, Mines and Resources Canada commissioned a study in the late 1970s to assess the commercial, economic and technical potential for steam turbine cogeneration in Canada.[12] The study was limited to the potential for unexploited cogeneration by boilers equipped with a back-pressure steam turbine, in industrial plants with steam demand in excess of 100,000 pounds per hour. A subsequent update to the assessment of economic potential was undertaken in 1982.[13]

A summary of the results of these studies is provided in Table 4.4. With natural gas as the preferred fuel, commercial potential was estimated at 224 MW. Average payback was calculated at 25 years under constant real electricity prices and 17 years assuming 2 percent annual growth in real electricity rates. When wood wastes were assumed to be the preferred fuel in the forest products sector, overall commercial potential was found to increase to over 970 MW. The greatest commercial penetration was found in the Maritime provinces, although that region represented only 8 percent of the total feasible projects assessed in the study. Inclusion of wood wastes improved considerably the commercial potential for cogeneration in British Columbia, Quebec, Manitoba and Ontario. The greatest commercial potential was found in the forest products sector, petroleum refineries, and the iron and steel industry. No other industries exhibited commercial potential for cogeneration applications.

Economic potential was identified by appraising each project from a public, rather than company, perspective. The resource cost of electricity from potential cogeneration installations was compared with the cost of electricity from new conventional supply projects, with all resources valued at their social cost. A full 82 percent of all cogeneration installations were found to be economically feasible under this assessment, representing just under 2300 MW of generating capacity. In absolute terms, the greatest economic potential was found in British Columbia, Quebec, Ontario and Alberta. In the latter cases, the majority of additional cogeneration potential was found to reside in the chemicals and petroleum refining sectors, respectively.

4.4.2 Manitoba

A 1982 study of the potential for cogeneration and waste heat recovery in Manitoba identified 13 establishments which were technically capable of cogenerating.[14] Potential capacity was identified at 44 MW using steam turbine technology and 168 MW using gas turbine technology. None of the sites were found to be commercially feasible, due primarily to the low cost of electricity in the province, against which a cogeneration installation would have to compete.

4.4.3 Other Jurisdictions

Research into the commercial and economic potential for industrial cogeneration is underway in Nova Scotia, New Brunswick and Ontario. In the Maritime Provinces, research is focusing on wood

TABLE 4.4

POTENTIAL FOR INDUSTRIAL STEAM TURBINE COGENERATION
(capacity in megawatts)

	Commercial Potential[a]		Economic Potential[b]		Technical Potential[c]
	Natural Gas Fuel	Wood Waste Fuel[d]	Natural Gas Fuel	Wood Waste Fuel[d]	
British Columbia	21	350	570	574	891
Alberta	0	25	337	337	776
Saskatchewan	0	0	33	33	53
Manitoba	0	18	44	44	59
Ontario	0	133	572	578	1477
Quebec	52	280	508	516	694
New Brunswick	66	80	92	92	144
Nova Scotia	85	85	109	109	174
TOTAL	224	971	2265	2283	4268

SOURCE: An Economic Update of the Potential for Cogeneration in Canada: Industrial Steam Turbines. Ottawa: Energy, Mines and Resources Canada, August 1982.

[a]Financially feasible cogeneration capacity, assuming constant real electricity prices over the service life of the installation.

[b]Economically feasible cogeneration capacity, as assessed against the province-specific supply prices of conventional power generation.

[c]As reported in Study of the Potential for Cogeneration in Canada, Energy, Mines and Resources Canada, December 1979.

[d]Utilization of wood waste in forest products applications, rather than natural gas.

burning and wood waste cogeneration technologies. Ontario possesses the largest absolute potential for industrial cogeneration applications among the provinces. In Ontario, the greatest interest is being directed to applications in the northern areas of the province.

4.5 Summary

The development of industrial cogeneration in Canada has been almost exclusively a private sector initiative. The majority of current installations are found in the forest products sector, where combustion of wood wastes enhances greatly the financial feasibility of such developments. The pace of development in other sectors has slowed considerably relative to expectations formed in the mid-1970s. This has been due largely to the high growth of fossil fuel prices relative to electricity rates in that period.

Given the limited number of financially viable industrial cogeneration prospects, future development will likely require significant changes in policy and procedures by both the electric utilities and provincial governments. Areas of potential policy development include interconnection requirements, provision of wheeling service, provision of standby power, reassessment of existing buyback rates, and direct and indirect assistance in reducing front-end capital costs. All of these policies presume a positive attitute within industry to the implementation of cogeneration facilities. In the next chapter, a discussion is provided of the perspectives of industry, utilities and government regarding the desirability of cogeneration and the factors which would contribute to the development of industrial cogeneration potential in Canada.

Footnotes

[1]Amendment to the Income Tax Regulations Pertaining to Class 34 Accelerated Capital Cost Allowance, December 13, 1984.

[2]Critics of utility policy would argue that this lack of experience is, in part, due to excessively low buyback rates for surplus cogenerated power.

[3]Ontario Hydro, Parallel Generation: Rates and Service Conditions (Toronto: Ontario Hydro, July 1985), P. 1.

[4]See Ontario Hydro, supra footnote 3, and Parallel Generation: Interconnection Requirements (Toronto: Ontario Hydro, July 1985).

[5]For a discussion of these cases (all relating to other forms of parallel generation) see Passmore Associates International, U.S. Utility Attitudes and Experiences with the Public Utility Regulatory Policies Act (PURPA) and its Potential Relevance in Canada, report prepared for the Renewable Energy Division of Energy, Mines and Resources Canada, Contract Serial No. ISQ84-00343 (Ottawa: Conservation and Non-Petroleum Sector, EMR, March 1985), pp. 77-78. For example, in a 1984 Alberta decision, a farmer was allowed to "bank" his wind-generated electricity in the utility (TransAlta Utilities) grid and to draw on his credit during low or no-wind periods. Rates for surplus sales to the grid were to be tied to the utility avoided cost and to be re-evaluated on a quarterly basis. See Alberta Energy Resources Conservation Board, Wind-Powered Electric Generator of A. E. Sinnott Near Pincher Creek, Decision D 84-12 (Calgary: ERCB, June 1984).

[6]H.D. Miller and W. D. Gibson, Utility Policy on Cogeneration and Small Power Production. Report Prepared by TransAlta Utilities Corporation for the Canadian Electrical Association, Contract No. 340 U SOA (Montreal: CEA, October 1984). The utility survey in this report was updated with a subsequent survey by TransAlta Utilities in April of 1986.

[7]The updated CEA survey covered 12 utilities: Alberta Power Limited, B.C. Hydro, City of Calgary Electric System, Edmonton Power, Hydro-Quebec, Manitoba Hydro, Maritime Electric Company, New Brunswick Electric Power Commission, Nova Scotia Power Corporation, Ontario Hydro, Saskatchewan Power Corporation, and TransAlta Utilities.

[8]Alex Juchymenko, "Utility Policies Towards Customer Owned Generating Facilities," report prepared by Cogeneration Associates Limited for the Canadian Electrical Association, Contract No. 416 U 465 (Montreal: CEA, October 1985), P. 85.

[9]Currently, the only public process for evaluating rates is the utility's annual hearing to review its proposed retail price changes. This forum is not normally used to discuss the price of customer-owned generation.

[10]J. E. Mitchell, "The Role of Ontario Hydro," Presentation to the Wood Energy Conference, sponsored by the Ontario Ministry of Energy, Timmins, Ontario, October 1986, P. 4.

[11]The rate structure also includes winter and summer energy charges.

[12]Acres Shawinigan Limited, Study of the Potential for Cogeneration in Canada; Industrial Steam Turbines, Conservation and Renewable Energy Branch, Energy, Mines and Resources Canada, December 1979.

[13]Acres Consulting Services Limited, An Economic Update of the Potential for Cogeneration in Canada; Industrial Steam Turbines, Conservation and Renewable Energy Branch, Energy, Mines and Resources Canada, August 1982.

[14]Scouten, Mitchell, Sigurdson and Associates Ltd., Cogeneration Associates Limited, Cogeneration and Waste Heat Recovery, 1982.

Chapter 5

PERSPECTIVES ON INDUSTRIAL COGENERATION

Development of cogeneration in Canada depends not only on the economic, financial and technical feasibility of implementation, but also on the perspectives of the various parties involved as to the costs, benefits and desirability of implementation.

This chapter provides an assessment of perspectives on industrial cogeneration in Canada on the part of industry, the utilities and government, based on responses to questionnaires and telephone surveys conducted in the second half of 1986. The industry and utility questionnaires are reproduced in Appendices B and C to this report, respectively.

Industry Perspective

The main objective for industry is to produce its products in the most efficient way possible. For most industries, energy costs are a relatively small component of total operating costs, compared to labor and non-energy materials. However, control of all cost components is a crucial element in industrial planning, particularly for relatively energy-intensive industries which face strong competition in domestic and international markets.

From an industry perspective, the direct benefits of cogeneration consist primarily of savings in total energy costs from displacing electricity purchases, and any revenue from the sale of surplus power. Indirect benefits may be derived from improvements in steam quality (temperature and pressure), electricity quality (e.g., reliability) and product quality. Direct costs include the capital cost of installing the cogeneration system, fuel and other operating costs, expenditures for maintenance during periods of downtime, and utility-related costs if the facility is connected to the grid (e.g., standby charges, interconnection charges).

Utility Perspective

The main objective of a utility is the provision of safe, reliable energy at the lowest possible cost. From the utility perspective, industrial cogeneration may be viewed as a provincial planning resource much the same as utility-owned generation. Cogeneration may also be seen to be a competitor for base load, removing industrial demand from the system.

The direct benefits of cogeneration to a utility include savings in capacity and energy costs derived from the reduction, if any, in required system generation capacity, and savings in fuel and operation and maintenance expenses. Indirect benefits may include diversification of fuel mix (e.g., development of wood wastes and other alternative fuels), improved relations with industry and the public, and any reduction in total environmental emissions due to more efficient fuel use. Direct costs to the utility include loss of base load and associated revenue, payments for buyback power, and risks to ratepayers from reliance on cogenerated power. Additional costs may be incurred through financial incentives to potential cogenerators or equity participation in cogeneration systems, if the utility chooses to play a more active role.

Society Perspective

The main concern for society is the net benefit derived from devoting scarce resources to cogeneration as opposed to alternative uses. This is a broader perspective that goes beyond the 'private' viewpoints of industry and utilities, to encompass such factors as employment impacts and environmental concerns which may not be totally captured in private accounting costs.

5.1 Industry Perspectives

Investment in cogeneration is basically neutral with regard to the volume of final product, the main concern of a business firm. Benefits accrue to the firm through increased efficiency of energy use, offset of electricity costs, and possible revenue from the sale of surplus power to the utility grid. Against these benefits are set the costs of capital, finance charges, plant retrofit, and operation and maintenance of the facility. In addition, the evaluation of a cogeneration facility is placed within the context of all other investment

opportunities available to the firm in order to efficiently allocate available investment funds.

This section provides a summary and discussion of the responses to a survey of current and potential industrial cogenerators, conducted by the Canadian Energy Research Institute in the fall of 1986. The survey provides industry perspectives on those factors which tend to encourage or discourage cogeneration development and on the roles of utilities and government in the decision-making process.

5.1.1 Survey of Industry Perspectives

It must be noted at the outset that the results of the industry survey discussed below cannot be extended to the entire industrial base in Canada. The survey was directed to those industries which could be termed potential cogenerators, that is, industries characterized by some combination of high energy costs, large thermal requirements, combustible waste by-products from production, and so on. The results do, however, summarize the perspectives of those industry groups most relevant to an assessment of cogeneration development in Canada.

Responses to the survey were received from firms representing ten key industrial groups, as defined by their major product category, across nine provinces (see Table 5.1). Over 70 percent of responses were from firms operating in the forest products, petroleum products, chemicals and mining industries. Roughly 50 percent of these firms were located in Central Canada and a further 37 percent in Alberta and British Columbia.

The survey contained a number of questions regarding the operating characteristics of the firms. Eighty percent of respondents reported fuel and electricity costs in excess of 6 percent of total annual operating costs. Over three-quarters of the firms used fuel oil or natural gas as a major process feedstock. One-quarter used biomass (combustible waste by-products) as a major feedstock, with the majority of these operating within the forest products sector. Some 40 percent of the respondents are large electric power consumers (electric demand in excess of 40 MW) with electric energy consumption in excess of 200 GWh per year.

Thirty percent of respondents already have cogeneration facilities in place, representing a combined capacity of 1046 MW (see Table 5.2). Of the total installed capacity, 39 percent is in the forest

TABLE 5.1

INDUSTRY SURVEY RESPONSES
BY PROVINCE AND INDUSTRY CLASSIFICATION

Province	Survey Responses		Industry Classification	Survey Responses	
	No.	% Total		No.	% Total
British Columbia	27	20	Forest Products	43	31
Alberta	24	17	Petroleum Products	19	14
Saskatchewan	5	4	Chemicals	22	16
Manitoba	4	3	Mining	14	10
Ontario	46	33	Manufacturing	4	3
Quebec	20	15	Food and Beverage	12	9
Newfoundland	2	1	Textiles	3	2
Nova Scotia	7	5	Iron and Steel	11	8
New Brunswick	3	2	Other Mineral Prods.	9	6
Prince Edward Island	0	0	Metal Products	1	1
TOTALS	138	100		138	100

SOURCE: Canadian Energy Research Institute. Data compiled from responses to industrial survey, Fall 1986.

TABLE 5.2

INSTALLED COGENERATION CAPACITY BY
PROVINCE AND INDUSTRY CLASSIFICATION

Province	Survey Responses		Industry Classification	Survey Responses	
	Total Reported Capacity (kW)	Average Installation Size (kW)		Total Reported Capacity (kW)	Average Installation Size (kW)
British Columbia	245,943	18,900	Forest Products	407,943	21,500
Alberta	406,395	50,800	Petroleum Products	152,565	50,900
Manitoba	21,000	21,000	Chemicals	383,000	127,700
Ontario	329,300	30,000	Mining	55,150	11,000
Quebec	24,200	8,100	Food and Beverage	31,700	6,300
Nova Scotia	3,250	1,600	Textiles	4,000	4,000
New Brunswick	16,000	8,000	Iron and Steel	11,730	2,900
TOTAL	1,046,088			1,046,088	

SOURCE: Canadian Energy Research Institute. Data compiled from responses to industrial survey, Fall 1986.

products sector, 37 percent in the chemicals sector, and 15 percent in the petroleum products sector. The average installation size varies considerably across sectors, with the chemicals sector having the largest average capacity installations. On a provincial basis, 39 percent of reported installed capacity is located in Alberta, 31 percent in Ontario, and 24 percent in British Columbia.

In addition to those currently operating cogeneration facilities, eleven firms reported to be planning for or constructing cogeneration capacity at the time of the survey, representing a total of 875 MW of generating capacity.

5.1.2 Factors Constraining Implementation of Cogeneration Technology

To identify those factors which were viewed as constraints to the adoption of cogeneration technology, all respondents who were neither currently engaged in cogeneration nor planning to do so in the future were asked to comment on a list of factors affecting the implementation decision. The list covered technical and financial factors, utility policy, government involvement, and company attitudes and constraints.

5.1.2.1 Technical Factors

In general, technical considerations were not viewed to be a significant constraint to the adoption of cogeneration technology. Concern over an inappropriate balance of thermal and electric load was the constraint most often cited. In some cases, it was noted that production technology had developed in a direction not conducive to the production of high temperature waste gases suitable for cogeneration. To justify the development work required to raise exhaust temperatures to levels sufficient for cogeneration would require long-term agreements on the sale of excess power and on buyback rates. Similar comments were provided with regard to priority thermal cogeneration facilities in general. The respondents were generally well informed of the available cogeneration technologies and listed reliability of the technology and difficulty of retrofitting of existing plant facilities as minor technical issues in the implementation decision. A number of respondents did comment that the decision to cogenerate should be made at the plant construction stage, in order to eliminate both retrofit costs and the need to replace an adequate production process with new technology. The capital cost of the latter was viewed as placing

unacceptable demands on the expected benefits of cogeneration, in terms of payback period and internal rate of return to the investment.

5.1.2.2 Financial Factors

Financial factors appeared as the key constraint to adoption of cogeneration technology. Return on investment, availability of financial capital, and priority of cogeneration in relation to other projects were cited as very significant factors in the decision-making process. Central to this issue is the fact that, from the company perspective, cogeneration is primarily aimed at reducing energy costs and does not increase the volume or quality of final output. Capital availability was viewed as a serious constraint on the expansion of manufacturing plant and equipment and, as such, an even greater constraint to the construction of electric generation capacity.

Implementation of cogeneration capacity is usually assessed on the basis of external (rather than equity) financing, with relatively high project hurdle rates and low payback periods. Of the total number of respondents, over two-thirds specified an internal rate of return (IRR) requirement of 20 percent or greater for construction of a cogeneration facility. A full 30 percent of respondents specified an IRR requirement in excess of 30 percent. Similarly, over three-quarters of all respondents specified a maximum before-tax payback period of 4 years or less for construction of a cogeneration facility, and over 30 percent specified a payback period of under two years.

Of those companies currently operating cogeneration facilities, a number commented that the high capital cost of the facility, combined with the low expected return on investment under current business conditions, would lead them to decide not to undertake a cogeneration project if the decision were being made today.

5.1.2.3 Utility Policy

The key elements of utility policy related to existing electricity rates and utility buyback rates (i.e., utility purchase of excess energy supplied to the grid by the cogenerator). The majority of respondents viewed the relatively low cost of industrial electricity in most regions of the country as a major impediment to adoption of cogeneration. The payback period on the capital expenditure required to construct a cogeneration facility was, in most cases, deemed excessively long using avoided cost of electricity at existing

industrial rates as the prime revenue offset. Respondents who referred to prior studies undertaken to evaluate the adoption of cogeneration at their plants cited low industrial electricity rates as the prime factor operating against adoption of the technology. Exceptions to this were noted by respondents located in isolated regions or relatively high-cost utility jurisdictions (e.g., Atlantic provinces).

Utility buyback rates were the second most significant utility policy variable in constraining cogeneration development. As noted in Chapter 4, buyback rates in Canada are not determined according to a governing principle such as the avoided cost rule used in the United States. In general, buyback rates are set at, or below, industrial rates. Clearly, this has a significant impact on the economics of cogeneration by reducing the revenue credits derived from the sale of surplus power to the grid, relative to a rate structure based on avoided cost of utility electricity generation. Buyback rates set at or below industrial rates also discourage the construction of facilities sufficiently large to generate surplus power, thereby potentially eliminating economies arising from larger scale facilities.

A number of respondents alluded to a perception of utility disinterest in cogeneration and, in some cases, utility policies of not purchasing excess power available to the grid. The lack of utility action and support for cogeneration was also perceived as a lack of support for the technology in general, given the amount of utility research already undertaken on cogeneration and alternative generation technologies.

5.1.2.4 Government Involvement

Government involvement in cogeneration development, in terms of required legal procedures, potential regulation, or environmental protection legislation, was viewed as insignificant in affecting the decision to cogenerate. This likely reflects the neutral position taken by most provincial governments with regard to non-utility electricity generation. The government of Ontario may depart from this stance with the release of a policy statement on parallel generation early in 1987.

One respondent made a comment concerning the regulations surrounding current government assistance. In particular, requirements for application for assistance prior to internal budget commitment or agreement on release of technical information to the government

prevented realistic access to available funds. A loosening of requirements regarding disclosure of project detail and possible adoption of a reward-oriented assistance scheme, perhaps based on a post-installation audit, would be more useful from the company standpoint.

On the other hand, it should be noted that three of those companies currently operating cogeneration facilities listed availability of public sector financial assistance as a key factor in the decision to cogenerate.

5.1.2.5 Company Attitudes and Constraints

Internal attitudes regarding cogeneration were generally viewed as insignificant in constraining the decision to cogenerate. Availability of expertise within the company, research and development requirements, and information regarding available technologies were all viewed as minor roadblocks to implementation. A significant number of respondents did, however, cite as detrimental the attitude that electricity generation was not the business of the firm. Investment in cogeneration and operation and maintenance of the facility would detract from the primary function of the company, without adding to output. Such resistance could be hard to overcome and may necessitate a greater role for third-party finance and facility operations in future development of cogeneration.

5.1.3 Factors Encouraging Implementation of Cogeneration Technology

To identify those factors which would encourage adoption of cogeneration technology, all respondents were asked to comment on a list of technical, financial, utility and government issues related to the implementation decision. Technical factors were viewed as insignificant, reflecting the perception discussed above that the availability and flexibility of existing cogeneration technology was sufficient to meet the needs of industry.

5.1.3.1 Financial Factors

Availability of financial capital and easing of internal budget constraints are paramount among respondents in promoting cogeneration development. The option of joint utility/cogenerator financing was viewed positively by the majority of respondents as a means of alleviating the financial constraints on implementation. However,

respondents were strongly against the option of utility ownership of cogeneration facilities, with steam sales back to the plant owner. One respondent commented that an analysis of utility ownership of a prospective cogeneration facility yielded steam purchase rates well in excess of the costs of internal steam production at the plant site.

Surprisingly, the role of third-party financing received little support among the industries surveyed. This option has received considerable attention in the United States, although the role of avoided cost-based buyback rates has been central in encouraging this development.

5.1.3.2 Utility Policy

A significant rise in industrial electricity rates and/or an increase in utility buyback rates were viewed as very positive factors in cogeneration development. This reflects the critical role of electricity pricing in the financial assessment of prospective cogeneration installations. Utility purchase of surplus power from a cogeneration facility, as opposed to interconnection alone, was regarded as an essential element for successful development of cogeneration potential.

A number of utility policy options were raised by the respondents as vehicles for promoting cogeneration development. Of most interest was the option of a time-of-use buyback rate structure, applied to the energy component of the buyback rate, which would provide an incentive for electricity sale to the grid during periods of peak demand. Such a structure would also more accurately reflect the value of parallel generation to a utility by linking buyback rates to the operating cost of the utility's peaking capacity.

5.1.3.3 Government Involvement

The majority of respondents perceived a positive and active role for direct and indirect government involvement in the development of cogeneration in Canada. High on the list of possible direct actions were enhanced tax relief directed to depreciation of capital and greater availability of capital grants and loans. Relief on up-front capital expenditures would greatly affect the economics of implementation and reduce the importance of purchase and buyback rates for electricity in the financial evaluation of a proposed installation.

A considerable degree of support was also registered for the development of supportive legislation, aimed at establishing rules regarding utility interconnection, calculation of buyback rates, sale of surplus power to the utility, and arrangements for wheeling of power within the system grid. Support for such legislation was strongest within the petroleum products and chemicals industries. For these industries, the option of a provincial or regional perspective on cogeneration with the host utility wheeling surplus power to the company's plants within the utility boundaries could prove sufficient to turn around the marginal economics of a plant-specific cogeneration strategy. Such an option would also carry a much higher risk factor associated with uncertainty as to the shape and permanence of utility policies, and thereby enhance the need for regulations regarding the utility-cogenerator interface.

5.1.4 General Observations

Based on the perspectives and comments provided by respondents to the industry survey, it is clear that the decision to cogenerate is a purely economic, and largely internal, one. The key factor in limiting cogeneration development is the payback period and return on investment from facility construction, particularly in an environment of limited financial capital. The hurdle rates provided by respondents for cogeneration development were relatively high, reflecting the lack of a direct contribution from cogeneration to a company's primary product.

It is somewhat ironic that the ability on the part of most utilities to generate low cost electricity (particularly for hydro-based generating utilities) is the key factor constraining the development of cogeneration. The existence of surplus generating capacity in many utility networks in turn diminishes the incentive for utilities to promote cogeneration through buyback rate-based incentive structures. In the absence of such incentives, the way may be open for government to implement policies designed to partially offset the front-end capital cost penalty incurred in construction of a cogeneration facility. This in turn assumes that governments in fact want to actively promote cogeneration development within their jurisdictions (see Section 5.3).

From a societal standpoint, one respondent noted that it is unacceptable to consume a nonrenewable resource (e.g., fuel oil, natural gas, coal) in electricity generation while wasting a renewable

one (e.g., waste by-products, process gases). Therefore, cogeneration applications yielding a benefit in terms of efficiency of fuel use should be pursued. Against this sentiment must be placed, however, the observation of another respondent that the encouragement of expansion of non-utility generating capacity must not lead to an inefficient utilization of resources nor to an inefficient capacity configuration and system expansion plan for the utilities.

5.2 Utility Perspectives

The feasibility of industrial cogeneration development is directly influenced by utility attitudes and policies with respect to customer-owned generation. These attitudes and policies are, in turn, a function of such factors as the generation mix, fuel costs, reserve margin, load growth, transmission capability, and government policies in the particular province.

There is a perception that Canadian utilities, as a whole, have not been very supportive of cogeneration and small power production. In some jurisdictions, this lack of support can be attributed to the presence of significant amounts of surplus generating capacity. Alternatively, utilities may show limited interest in cogeneration either because they have received few proposals from industry or because they view cogeneration as a small part of total provincial resources. Critics point to a number of manifestations of utility attitudes towards customer-owned generation:

- reluctance to purchase excess power from the customer;
- low buyback rates;
- excessive rates for standby power; and
- refusal to wheel electricity for the customer.

Recently, however, a number of utilities have been reviewing their interconnection and purchase policies, with the object of facilitating development of alternative resources. This reflects, in part, a recognition of the long-term potential of cogeneration in deferring new capacity in the provincial electric system.

In this section, we examine utility views on the advantages and disadvantages of industrial cogeneration development. In addition, we

consider attitudes towards the role of utilities in fostering that development. Much of the discussion is based on a telephone survey of Canadian electric utility representatives conducted throughout September and October of 1986.

5.2.1 Concerns about Cogeneration

To date, utilities have expressed a number of concerns about the development of industrial cogeneration. These concerns are particularly strong where cogeneration would serve as a provincial planning resource.

It is important to realize that an electric utility combines the viewpoints of several different groups, each with its own concerns and requirements. Some of the key viewpoints are:

- System operators - Utility system operators are concerned with the impact of a cogeneration system on the technical integrity of the system (voltage, harmonics, etc.), safety of utility employees, and generally on the quality of service to other customers. They want to know about control over the cogeneration system in terms of scheduling and availability. How reliable is the equipment and how skilled are the maintenance personnel? What are the potential effects on system economics in terms of escalating fuel and operation and maintenance costs?

- Generation planners - When projecting additions to system capacity, generation planners feel reasonably confident about the resources over which they have control. Industry-owned cogeneration can add another wrinkle to the planning process. To what extent will the cogeneration capacity fit with utility requirements with regard to size, location, in-service date and reliability? What are the chances that the capacity will not be available as planned, due to decline of the industry or some other event?

- Fuel planners - Utility fuel planners may have specific goals for the system in terms of diversification of the generation mix. Therefore, one of their concerns vis-a-vis cogeneration is whether the cogenerator's choice of fuel(s) will be consistent with their own long-term fuel procurement planning. Will the cogeneration contribute to total environmental emissions, or will it be based on a more benign fuel source (e.g., natural gas)? Will it serve provincial policy objectives, for example, promoting greater use of waste fuels and indigenous energy sources?

What are the risks of cost escalation associated with particular fuels? Does the cogenerator have access to long-term fuel supplies to the same degree as the utility?

- Transmission planners - As in the case of generation planning, cogeneration can complicate the planning process for a utility's transmission and distribution (T & D) engineers. T & D networks are planned on a regional basis to balance with system demands and supply capability. The appearance of a cogenerator at a particular location can alter that balance, especially if the size of his capacity is relatively large. Additional equipment may be required at the local level to protect not only the cogenerator but other customers as well. Alternatively, introduction of cogeneration capacity may alleviate problems in a transmission-constrained area, or may result in the deferral of a new transmission network. What is the effect of a pool of cogenerators on reliability of the transmission network? Are there significant reductions in losses to be gained from locating generation near the point of consumption?

- Rate-makers - A source of potential concern on the part of utility rate-makers is the impact of a loss of base load and revenue resulting from increased cogeneration activity. Rate-makers are concerned with fairness in the rate structure and cross-subsidization between different customer classes. Will cogeneration substantially raise costs to the remaining utility system customers? Moreover, what are the risks to the ratepayer of relying on industry-owned generation for future firm power needs? If the cogeneration is not installed according to the planned in-service schedule, then the utility may have to resort to higher cost capacity additions. Rates could also be affected by escalation in the fuel and maintenance costs of cogeneration. Yet another issue is how to determine buyback rates and charges for providing standby power and wheeling services to the cogenerator.

- Marketers - A utility's marketing department is likely to be concerned about how cogeneration fits into the overall strategy for market development. Over the short term, the loss of industrial load may be an important consideration. In fact, a number of Canadian utilities are currently offering discounts on the price of electricity sold to industrial customers. Therefore, the development of cogeneration may run counter to short-term goals of marketing the utility's surplus capacity. Other issues include: (1) how can cogeneration contribute to long-term policy with regard to demand management?; and (2) how do other customers feel about cogeneration as a planning resource?

- Load forecasters - Clearly, the potential for future cogeneration is of some concern to load forecasters for their evaluation of long-term requirements. The main problem in load forecasting relates to the lead times needed to commission new facilities. Forecasters want to know whether they can consider cogeneration as an interim, short lead time option in the planning horizon. Thus, the develoment of cogeneration may actually help to reduce demand uncertainty.

For the purposes of this study, Canadian electric utilities were asked in a brief survey to identify their main concerns regarding cogeneration development. A list of potential items was provided:

- Loss of base load - The loss of high load factor industrial customers can mean not only reduced revenues but also increased unit costs (costs per kilowatt) for the remaining customers on the system. This follows from the notion that a larger share of the remaining customers would be served by more costly intermediate and peaking capacity. Loss of load is likely to be a short-term factor since, in the long-term, it will tend to be offset by load growth and any deferral of new base load generating plant. Of the 10 major utilities surveyed, seven responded that loss of base load due to industrial cogeneration was not a significant concern to them. Most of the respondents commented that it was not a pressing issue, given that cogeneration currently accounted for a small percentage of their load. Four utilities felt that loss of load could become important if there was to be a major expansion in cogeneration capacity (e.g., in the pulp and paper industry). One utility added that, even in such a case, loss of load would not be a valid reason for discouraging cogeneration activity.

- Aggravation of surplus capacity - Over the short term, cogeneration may contribute to excess system capacity at a time when the utility is actively trying to market its electricity. There may also be a problem over the long term if the cogeneration equipment is installed to serve firm power needs. For example, if load growth declines and the cogeneration capacity appears redundant, the utility may feel that it has little control over the in-service schedule. An offsetting factor is the shorter lead time of cogeneration facilities, which may make them more flexible in meeting changes in demand growth. In the survey, roughly half of the utilities indicated that the issue of surplus capacity was significant in their view of cogeneration development.

- Short-term reliability and maintenance of cogeneration equipment - There is some concern about the availability of cogeneration units, in particular, the risks of unscheduled outages. If a utility is relying on the cogenerator for capacity, and that capacity is not available as scheduled, then the utility will have to provide backup generation from its own resources. Six survey respondents felt that reliability was a key concern, and two added that the performance of the cogeneration equipment would have to be comparable to utility-owned and operated capacity.

- Need to provide standby power for the cogenerator - This is an extension of the reliability issue outlined above. It has been argued in the past that a utility would have to provide full standby capacity for cogeneration equipment and that as a consequence, there would be no saving in terms of deferred utility plant. Again, six of the survey respondents cited this as being a significant concern. One respondent noted that a utility could find itself in the position of installing backup capacity, with less load over which to spread the attendant capital costs.

- Long-term availability of cogenerated power - All of the utilities except for one expressed concern over the long-term availability of cogenerated power. Long-term availability issues relate to survival of the industry, access to extended fuel contracts, future trends in relative fuel prices, etc. In order to defer capacity additions, a utility would generally require some sort of guarantee of availability (e.g., through a long-term contract) from the cogenerators on the utility system.

- Lack of direct operating control over cogeneration facilities - This factor was considered significant by eight of the respondents. Of the remaining two utilities, one stipulated that, according to its policy, committed cogeneration capacity would have to be included in the provincial dispatch of generation. Typically, direct dispatch would be the preferred operating regime from the point of view of the utility. Alternatives would include some form of scheduled operation according to season, time of day, etc.

- Risk to ratepayers - One of the principal risks of cogeneration development is that it can result in higher costs of generation to other utility customers. For example, there is the possibility that the cogeneration equipment will not be built by the in-service date, so that the utility must install high cost, short lead-time capacity (e.g., gas turbine peaking units).

Alternatively, load growth may decline, in which case the capacity becomes redundant. It should be noted that these kinds of risks also apply to utility-owned resources. However, utilities may perceive cogeneration to be inherently less dependable because of their lack of control over it. Seven of the survey respondents indicated that risk to ratepayers was an important concern. A comment was made that this risk should be compensated for by sharing the benefits of cogeneration (e.g., savings in capital and fuel costs) between cogenerators and the utility ratepayers.

- Additional complexity of the planning process - As mentioned earlier, cogeneration can complicate the utility planning process. System planners may find it difficult to fit several small cogenerators into their long-term demand and supply strategy. A greater number of players may also add to the process of obtaining regulatory approval. Furthermore, there is the administrative task of negotiating individual contracts with all of the cogenerators. Six surveyed utilities felt that this was a significant area of concern. Of the rest of the utilities, one stated that the regulatory process would only be substantially affected if PURPA-type legislation were to be introduced.

- Other concerns - Utilities were asked to identify any other concerns which they might have with regard to increased cogeneration development. One utility representative indicated concern with respect to the role of future fuel costs in calculation of the feasibility of cogeneration development and, in general, the potential long-term benefits from cogeneration. A key factor in determining the long-term net benefits of an industry-owned and operated facility is how fuel costs escalate in relation to electricity costs. Therefore, a utility may be concerned about gas-fired cogeneration in the event that natural gas prices increase at a (substantially) faster rate than electricity prices, and no compensating provision has been made in the cogenerator's fuel contracts.

As a general comment, one of the utilities surveyed suggested that these concerns could all be effectively dealt with in a contract between the two parties. That is, a contract could be negotiated which would distribute the various risks and benefits between a utility and a cogenerator. For example, the price of purchased power from the cogenerator to the utility could be adjusted for reliability, and an operating schedule could be worked out to suit both parties.

5.2.2 Benefits of Cogeneration

In addition to identifying their concerns, utilities were asked to indicate what they perceived to be the major potential benefits from the development of industrial cogeneration. Generally speaking, cogeneration can result in benefits if power and/or energy can be produced at a cost less than the utility's avoided cost of supply. However, some individual benefits can be highlighted:

- Lower capital costs for new plant - Typically, cogeneration facilities are characterized by lower capital costs per kilowatt than utility generating stations. In the survey, seven utilities indicated that lower unit capital costs were a significant potential benefit of cogeneration. One utility maintained that this was not a significant advantage if the entire cost saving went to the industry owner.

- Lower construction risks - From the utility point of view, construction risks can be lower to the extent that the industry owner builds and finances the cogeneration facility. Alternatively, the utility could provide some financial assistance or even participate in a joint venture with industry. Both of these options would presumably result in lower construction risk than if the utility were to install its own capacity. A likely offsetting factor is the years of experience which a utility has in constructing generating stations. Half of the ten utilities surveyed felt that reduced construction risk was not a significant benefit.

- Increased flexibility due to smaller units - One of the difficulties in planning for electricity demand growth is the "lumpiness" of conventional supply options. A larger number of small units--e.g., cogeneration units--could lead to greater flexibility in meeting short-term fluctuations in load. On the other hand, in a relatively large utility system, load growth can amount to hundreds of megawatts per year. In this case, it would take many cogeneration projects to substitute for one or two central generating units. The majority (7) of the utilities felt that smaller units were not an important benefit. One utility specified that cogeneration units were probably not large enough for its system. Another, smaller utility indicated that most of its cogeneration potential was in the pulp and paper industry where unit sizes tended to be larger than average for industry-owned facilities.

- Increased flexibility due to shorter lead times - The lead time for a cogeneration system is generally less than 4

years, while a central power station can take up to 15 years to be placed in service. This shorter lead time is a function of such factors as equipment size, site acquisition, regulatory approvals, and transmission requirements. The advantage for planning purposes is that a cogeneration facility could be more responsive to unexpected changes in demand, e.g., to a drop in load growth. The opposing argument is that if load growth falls off it may be easier for the utility to adjust its expansion plan than to renegotiate its contracts with cogenerators. Most (6) of a utilities surveyed stated that shorter lead times were not an important benefit of cogeneration. According to one utility, smaller units and shorter lead times would only be an advantage if the utility had some control over the cogeneration capacity--for example, by assuming an equity position.

- Greater efficiency in the use of fuel supplies - This is the major rationale for cogeneration from a "societal" viewpoint. Less fuel is used to produce thermal and electric energy together than to produce them in separate processes. Seven utilities acknowledged fuel savings as a significant benefit associated with industrial cogeneration. One utility commented that it had access to relatively low cost mine-mouth coal, so that fuel savings were not a major concern on its part.

- Reduced transmission losses - There is potential for reduced transmission losses as a result of siting generation near to the industrial customers' loads. Reduced losses can, in turn, lead to a lower cost of electricity supply. Six of the surveyed utilities felt that lower transmission losses were not a key factor in recommending cogeneration development.

- Reduced transmission requirements and/or constraints - The majority (6) of the utilities also felt that reduced transmission needs/constraints were not a key potential benefit. One respondent stated that its cogeneration prospects were in pulp and paper plants located in areas other than where the system load was growing. As a consequence, the development of cogeneration would call for additional transmission support. Conceivably, a utility could realize savings in bulk transmission, particularly if the cogenerator was large and situated near major developing load centres. An example is the Dow Chemical Company in Sarnia, Ontario. The development of cogeneration capacity by Dow has prevented the overloading of existing transmission facilities serving the Sarnia area. Generally speaking, however, a parallel cogenerator will not lead to savings in the immediate transmission and distribution network, as the utility will likely still have to supply standby capacity.

- Increased stability of the grid - There may be advantages to the grid system in terms of diversity and reliability through the addition of smaller, dispersed generating units. Another source of diversity may be the use of different fuels such as waste by-products. The impact on system stability depends in large part on the reliability of the individual units. One of the key benefits of cogeneration may be its potential for strengthening the grid in remote areas.[1] In the utility survey, several respondents were uncertain about the ultimate effect on system reliability and felt that this was an area that would require detailed study. Only two utilities answered that increased stability of the grid was an important benefit.

- Environmental impacts - Relative to conventional utility resources, cogeneration can result in an easing of adverse environmental impacts because of factors like dispersed siting, smaller project size, and greater efficiency of fuel use. On the other hand, it could conceivably increase local impacts in areas which were already constrained with respect to environmental emissions.[2] Eight of the utilities surveyed maintained that a lower "concentration" of environmental impacts was not a significant benefit of cogeneration. One utility, however, did feel that it was highly significant.

- Public relations - A utility may perceive that its public image will be enhanced by encouraging the development of cogeneration. This could include: (1) an improved relationship and spirit of cooperation with its industrial customers; and (2) a softening of its image as a monopolist in the supply of electric power. In addition, there may be considerable public support for smaller-scale alternative energy options, of which cogeneration is a part. Eight utilities indicated that improved public relations were, indeed, a benefit from their perspective. Several respondents mentioned that their provincial governments were showing increased interest in cogeneration development.

- Other benefits - Two other potential benefits of cogeneration were cited in the survey: (1) deferment of higher cost facilities; and (2) customer benefits. From a provincial standpoint, a cogeneration project will be beneficial if it produces electricity at a cost lower than the utility avoided cost. If these savings accrue entirely to the industrial cogenerator, then he will benefit through lower energy costs and presumably, improved competitive advantage. If the benefits are shared with other provincial customers, then they also may benefit through lower costs of service.

5.2.3 Utility Role in Encouraging Cogeneration

Finally, utilities were asked what sorts of measures they would be willing to consider to encourage cogeneration development in their service areas. For ease of discussion, the measures can be classified under the categories of purchase and wheeling policy, "indirect" utility involvement, and "direct" utility involvement in cogeneration.

5.2.3.1 Purchase and Wheeling Policy

The majority (6) of the utilities surveyed stated that they would consider (or have considered) higher buyback rates for power purchased from industrial cogenerators. Most stressed that rates would have to be determined in relation to utility replacement value (avoided cost). Of the four utilities that responded in the negative, one commented that its buyback rates did reflect current replacement value. Another indicated that it would not consider an increase in its purchase rates while there was surplus capacity in its integrated system.[3]

Eight of the respondents said that they would be willing to consider capacity credits for purchases of, or access to, firm cogenerated power. One respondent emphasized that the credit should only become operative in the year in which the capacity is needed (i.e., the in-service date of avoided capacity additions). Two utilities stated that they would not consider capacity credits given their existing excess capacity positions.

On the subject of wheeling, two respondents indicated that they had already provided some form of transmission service to industry, and a total of eight were willing to examine any proposals in this regard. According to the remaining two utilities, transmission facilities were designed to serve all customers and it would be difficult to assign priorities among competing users.

5.2.3.2 "Indirect" Utility Involvement

Most utilities answered that they would consider the following assistance to prospective cogenerators: (1) participating in demonstration projects of cogeneration equipment; (2) offering technical and management programs (seminars, workshops, etc.); and (3) taking part in project feasibility studies. In fact, several of the utilities said that they had been involved in such activities in the past. One

respondent commented that feasibility studies could become expensive and that it might be advisable to charge the prospective cogenerator, beyond a certain level of expenditure.

The utilities were more divided on the issue of providing personnel to help build and/or operate the cogeneration facility: five responded positively and five were negative or uncertain. Comments were that it depended on staffing constraints and on the specific economics of the project.

5.2.3.3 "Direct" Utility Involvement

Almost unanimously--with the exception of one respondent[4]--there was a strong objection voiced to the notion of utilities providing financial incentives for cogeneration (direct loans, prepayment for purchased power, etc.). It was generally felt that incentives came under the domain of government, and not the electric utilities. The majority (7) of the respondents were more favourable towards joint venturing with industry to develop cogeneration systems. In addition, there was some support (6) for arrangements under which a utility would build and operate the cogeneration facilities and then sell electric and thermal energy to the industrial user(s). Other variations on the utility role which were <u>not</u> favored by most of the respondents include: serving as the operator for a facility owned by industry, and building (and owning) a facility operated by industry.

5.2.4 General Observations

In the course of this short survey, the participating utilities made a number of general points with respect to their view of industrial cogeneration:

- Most utilities maintain that they are willing to consider any proposal for cogeneration development on its own merit.
- In the provincial planning process, load growth should be met by the next lowest cost option for the system. If that option is a cogeneration facility, then it is worthy of consideration.
- From the utility perspective, cogeneration projects should be justified in terms of their relative economics. If, for other policy objectives, a provincial government wants

to encourage economically "marginal" cogeneration projects, then it should be responsible for supplying any related financial assistance to industry.

- Generally, utilities would not welcome a PURPA-type regulatory environment to foster the development of cogeneration. It is preferable to negotiate contracts with individual cogenerators which provide a mutually acceptable distribution of the risks and benefits of the project.

- If cogeneration is being considered as a provincial resource, and would result in savings over the utility avoided cost, then there is some justification for sharing these savings with other electricity consumers in the province (i.e., through reduced power rates). This would be particularly relevant if the cogeneration were to cause a significant erosion in base load, increasing unit costs to the remaining customers in the system.

- According to several hydro-based utilities, the current environment for cogeneration in their service areas is not favorable, given low industrial electricity rates and the extent of excess system capacity. However, over the long term (i.e., the post-2000 time frame), cogeneration could be used to diversify the generation mix and defer expensive hydro units.

- There is some feeling that, in the pulp and paper industry, a substantial share of the total cogeneration potential has already been developed.

- Utilities are generally willing to assist a prospective cogenerator by running his project scenarios through their system planning and other computer models.

- Any number of arrangements (joint venturing, third party financing, etc.) could be considered by a utility, depending on the specific economics of the project and the nature of the association with industry.

- Utilities feel that they are in a position to cooperate with industry not only to facilitate cogeneration but also to provide special services to industrial users such as price discounts and interruptible energy sales during off-peak periods.

5.3 Government Perspectives

In Canada, the development of policy relating to electricity eneration, transmission and distribution falls within the jurisdiction

of the provincial governments.[5] The federal government provides indirect support to industrial cogeneration development through the commissioning of studies and the establishment of intergovernmental financial agreements providing funding for research and demonstration projects. The latter are negotiated independently with individual provincial governments; therefore, the emphasis on cogeneration within these agreements varies considerably across jurisdictions.

Provincial policies and perspectives regarding industrial cogeneration were identified through a series of telephone interviews with government officials involved in the formulation of energy policy. A summary of the interview responses is provided below.

5.3.1 Current Perspectives on Industrial Cogeneration

At the present time, no provincial government has in place a formal policy respecting the development of industrial cogeneration. Perspectives on industrial cogeneration range from indifference to the development of existing potential, to a perception of cogeneration as an important component of electrical energy policy over the next 20 years.

5.3.1.1 British Columbia

Despite the significant amount of existing cogeneration capacity within the province's forest products sector, the government of British Columbia attaches little importance to cogeneration development within the government's overall policies on electricity, citing the current surplus capacity on the B.C. Hydro system as an argument against government involvement in the promotion of cogeneration. Within the forest products sector, the economics of waste utilization justify the implementation of cogeneration technology without the need for public sector support.

5.3.1.2 Western Provinces

The general position of the governments of the Western provinces is that development of industrial cogeneration is a private sector issue, requiring little government intervention beyond the provision of research funding and demonstration support. Relatively low industrial electricity rates, the result of inexpensive feedstock for fossil fuel-fired generation and/or abundant hydroelectric

generating capacity, reduce the economic and commercial viability of potential cogeneration installations. Accordingly, the case for direct government support of cogeneration development (if not the need) is also weakened.

Alberta likely possesses the greatest potential for parallel generation development among the Western provinces. The most interest, however, is being seen in the areas of wind energy and energy from waste. The greatest potential for cogeneration likely resides in the petrochemical sector and enhanced oil recovery applications. The position of the government is that this potential should be developed through private sector initiative. Assistance is available for research into cogeneration applications and development of demonstration projects.

Saskatchewan and Manitoba have both undertaken detailed studies into the potential for industrial cogeneration in their respective jurisdictions. In both cases, the findings revealed very limited economic or commercial cogeneration potential.[6] The Saskatchewan government does not perceive a role for industrial cogeneration in the province and does not have provisions in place to assist with the research or development of cogeneration applications. The Manitoba government remains generally supportive of industrial cogeneration and would support an application for sale of surplus power by a prospective cogenerator. However, this has not been an issue to date.

5.3.1.3 Ontario

Industrial cogeneration is receiving considerable attention from the government of Ontario as one component of a more general policy stance on the development of parallel electric power generation in the province. Cogeneration, along with alternative electric generation technologies, is regarded favourably from the perspective of efficiency of energy use (i.e., pursuing the most cost effective and efficient sources of incremental generation capacity within the province) and the support and development of indigenous industry and technologies. The government provides funding for research and development activities through a variety of programs, including:

(i) EnerSearch Program, providing funds for up to 50 percent of eligible expenditures on research, development, testing and demonstration of innovative energy technologies in the province; and

(ii) Northern Ontario Wood Energy Program, which provides financial assistance for the development of wood burning generation facilities in northern Ontario.

The government of Ontario is currently sponsoring a study designed to identify the technical, commercial and economic potential for cogeneration development in the province. On the basis of previous research, some 1000 MW of commercially feasible industrial cogeneration capacity is believed to exist in the province, representing a potential alternative to construction of a large-scale generating station to meet incremental load growth over the next 15 years. Cogeneration is also seen to offer considerable immediate potential for offsetting the need for new conventional electric generation capacity in many parts of the province and, in particular, the Northern region of the province where such development could eliminate the need for major new transmission facilities.[7] Industrial cogeneration is expected to receive considerable attention both as a demand option (offsetting a portion of forecast load growth on the Ontario Hydro grid) and as a supply option (through the provision of surplus power to the grid) within the electricity policy deliberations of the government in 1987.

5.3.1.4 Quebec

The attention of energy policy makers within the government of Quebec is focused on the development of small hydroelectric generation potential within the province. Potential for industrial cogeneration is perceived to be limited to the forest products sector and other waste-fired applications, due to the availability of inexpensive industrial power from Hydro-Quebec. The government is supportive of cogeneration applications based on waste-fired technologies, from the standpoint of enhanced fuel efficiency and competitiveness of the forest products industries. However, cogeneration is not viewed as a supply option within the electric energy policy of the government.

5.3.1.5 Atlantic Provinces

The Atlantic provinces contain considerable potential for small-scale industrial cogeneration applications and, to varying degrees, the provincial governments are supportive of such development. The government of Nova Scotia is currently studying the potential for wood-fired cogeneration applications in the province, under the auspices of a federal-provincial Memorandum of Understanding on Renewable Energy and Energy Conservation. Relatively high electricity

rates within the province tend to support the commercial feasiblity of cogeneration development. In the forest products sector, three-quarters of the pulp and paper mills currently cogenerate, using wood waste as the primary feedstock. Against the development of cogeneration, however, must be placed the current surplus capacity on the provincial utility's generating system. A compromise likely must be reached between these competing sources of electricity supply.

New Brunswick is expected to undertake studies on wood-burning cogeneration applications within the province, under a similar federal-provincial Memorandum of Understanding signed in December 1986.

Prince Edward Island actively promotes the development of energy projects through the PEI Energy Corporation. Potential for industrial cogeneration is limited by the relatively small industrial base of the province. In addition, the electric utility serving the province has acted in the past to discourage such developments (through the provision of incentive rates on industrial power) in order to maintain its industrial baseload. The provincial government recently completed a joint federal-provincial study on electricity options for the province, in which the limited potential for cogeneration applications was reaffirmed.[8]

The government of Newfoundland perceives significant benefits to the province from industrial cogeneration applications, particularly from combustion of waste fuels. An in-house study of the potential for waste-fired cogeneration identified some 25 MW of potential capacity, comprised largely of small-scale systems of under 1 MW. The provincial government has provided considerable support in the form of seed money for feasibility and engineering studies into prospective cogeneration applications.

Both Newfoundland and Nova Scotia expressed an openness on the issue of direct financial assistance from the government to aid in development of cogeneration potential. For the former, a role for direct assistance was perceived in the pulp and paper sector as firms move to replace their old boiler equipment. Assistance could be made available to promote the adoption of cogeneration technologies as a fuel-efficiency and cost-saving measure. In the case of Nova Scotia, assistance provided in the form of capital grants designed to lower the payback period (or raise the internal rate of return) on projects in order to comply with internal industry requirements was viewed as appropriate intervention. In both cases, however, the officials

contacted stated clearly that provincial assistance would not be used to pursue economically and commercially unattractive projects. In addition, the initiative for project development would have to come from the private sector, rather than from within the government.

In summary, the governments of Ontario and the Atlantic provinces are the most positive in their perspectives on industrial cogeneration. In Ontario, cogeneration is seen as a potentially important element in the medium- and long-term electricity supply and demand policies of the provincial government. Both directly and through Ontario Hydro, the government is seeking to encourage development of cogeneration, particularly in the isolated areas of the province.

In the Atlantic provinces, industrial cogeneration is regarded as a cost-effective way to enhance the overall efficiency of energy use within the region. Looking beyond the current weakness in crude oil prices, this is an important objective for a region dependent upon imports of liquid hydrocarbon feedstocks.

Industrial cogeneration receives considerably less public sector support within the remaining provinces, for a variety of reasons: availability of inexpensive hydroelectric power and/or fossil fuels, limited applications within the existing industrial base, or the relative potential importance of other alternative electric generation technologies.

5.3.2 Legislation Regarding Industrial Cogeneration

None of the government officials contacted in this survey perceived a role for legislation similar to that enacted in the United States regarding industrial cogeneration. The legislation option was perceived as being overly rigid and potentially counter-productive. Respondents pointed to the U.S. experience where, in some jurisdictions, the PURPA legislation had led to an excess of cogeneration capacity, inefficiencies in the utility supply configurations, and increased costs to ratepayers. The general response was that, by creating an environment which would not discourage industrial cogeneration development (i.e., a neutral or positive policy environment), those projects which are commercially and economically feasible will be developed. Active promotion of cogeneration development, through

incentive rate structures or direct capital assistance, could introduce a greater risk of inefficient use of resources within the industrial sector.

Footnotes

[1]For example, the Syncrude development in Alberta provides backup capacity to customers in the vicinity of Fort MacMurray.

[2]Note that a cogenerating system uses more fuel on site than a non-cogenerating (thermal energy only) system. Therefore, the local impacts of cogeneration in heavy industrial areas may outweigh the benefits of any overall fuel savings. Dilip R. Limaye, "Methodology for Evaluation of Cogeneration Projects," Paper Presented to the National Fuel Cell Seminar in Norfolk, Virginia, SRC Paper 906-56 (Bala Cynwyd, Pennsylvania: Synergic Resources Corporation, June 1981), pp. 12-13.

[3]The utility added that it was willing to consider higher buyback rates and capacity credits for its non-integrated service areas. In this case, non-integrated areas refer to more remote load centres served by diesel generating units.

[4]Ontario Hydro has been examining the possibility of providing direct financial incentives to industrial cogenerators.

[5]Under section 92(10) of the Constitution Act, 1867 (formerly the British North America Act, 1867) the provincial legislatures have jurisdiction over the generation and distribution of hydroelectricity, because dams, generating stations and distribution networks are deemed to be "local works and undertakings." Electricity generated from oil, coal, gas or other sources of energy are governed by the same constitutional principles as hydroelectricty. In addition, section 92A(1)(c) of the Constitution Act, 1967 (which was added to the Constitution in 1982) empowers each provincial Legislature to make laws in relation to "development, conservation and management of sites and facilities in the province for the generation and production of electrical energy." See P. W. Hogg, Constitutional Law of Canada, Second Edition, (Toronto: The Carswell Company Limited, 1985) pp. 596-7.

[6]The government of Manitoba commissioned a study on the potential for industrial cogeneration under the auspices of the federal-provincial Conservation and Renewable Energy Demonstration Agreement (CREDA). The study revealed technical cogeneration potential of 44 MW (steam turbine technology) of which 10.3 MW has been developed. Little of the remaining potential was found to be commercially feasible. See Scouten, Mitchell, Sigurdson and Associates Ltd., Cogeneration and Waste Heat Recovery, 1982, Section 5.

[7]The Ontario Ministry of Energy released an energy information paper in 1986 which discussed the views of the provincial government on alternative electric generation technologies. See Parallel Generation in Ontario, (Toronto: Ontario Ministry of Energy, March 1986).

[8]This study is expected to be released in the spring of 1987. Copies can be obtained through the PEI Energy Corporation.

Chapter 6

SUMMARY AND RECOMMENDATIONS

This study has provided a review of the technical, economic and financial factors affecting industrial cogeneration, a comparative assessment of the development of cogeneration in the United States and Canada, and a discussion of the perspectives on cogeneration held by industry, utilities and the government sector in Canada. A number of general observations can be drawn from this analysis. First, the technology of industrial cogeneration is well advanced and widely understood and accepted by both industry and the utilities. Available technologies are extremely flexible with respect to fuel type and optimum efficient system size. This is supportive of potential cogeneration applications for a large number of industries in a variety of geographical locations.

Second, cogeneration development has proceeded at a slower pace in Canada than in the United States, due to various factors including lower electricity rates and lower utility buyback rates. The implementation of the PURPA legislation in the United States provided a significant boost to the development of cogeneration and small power production in the 1980s. In particular, the requirement for utility interconnection with prospective cogenerators and the calculation of utility buyback rates based on the avoided cost of system generation laid the foundation for a rapid expansion of industrial cogeneration capacity. While the availability of utility interconnection has not been an issue in Canada, the lack of comprehensive provincial legislation regarding other aspects of the utility-cogenerator interface has been noted as a major factor in explaining the differential in the pace of cogeneration development between the two countries over the past eight years.

Third, while the assessment of perspectives on cogeneration on the part of industry, the utilities and government revealed a large number of factors both encouraging and discouraging cogeneration development in Canada, many of these relate to technical issues concerning the industry-utility interface which would be addressed through negotiation at the early stages of implementation. These

include reliability of the chosen technology, maintenance of the facility, adequate training and supervision of maintenance personnel, the technical requirements for the actual interconnection (e.g., allocation of incremental transmission costs, interconnect charges, system integrity, and so on), and other direct and indirect costs associated with the installation procedure. These factors are best addressed by the parties concerned, on a case-by-case basis.

A number of other factors, however, are more generic to the question of industrial cogeneration development in Canada. These can be categorized as financial factors, utility purchase and service factors, and public policy issues.

6.1 Financial Factors

Various financial constraints impinge on the ability of individual companies to develop projects which would be economic from a provincial perspective. On the one hand there are the capital availability contraints faced by companies and the internal hurdle rates (rate of return on investment and payback period) established for projects of this type. Industrial cogeneration offers potential benefits not only from the cogenerator's perspective (offset of electricity costs), but also from a provincial or societal perspective as well (efficiency of energy use, efficiency of electric power generation). **For this reason, it is possible to present a case for financial assistance from the government sector to offset part of the capital cost of cogeneration development, in order to enhance the internal rate of return on projects with a potential economic benefit.** It must be emphasized that such support should be provided only in cases where an economic benefit is perceived, and only within the context of an orderly and efficient development strategy which takes into consideration the system characteristics and expansion program of the relevant electric utility. It is important that the utilities and industry be in control of implementation, regardless of possible provision of financial incentives by the provincial governments.

On the other hand there are the charges for standby power and rates for purchased power which constitute the financial interface with the utility. Ideally, both of these variables should be linked to the marginal utility system cost, in order to provide appropriate price signals upon which to base economic and financial assessments of prospective installations. In Canada, purchase rates have been established in most instances at a level below the rate for electricity

sales to industrial customers. In some utility jurisdictions, a policy on purchase rates does not exist. **Utility purchase policy for parallel generation should be reviewed with regard to implementating a pricing system which accurately reflects the utility system cost of marginal generating capacity.** Establishment of purchase rates at utility system avoided cost, similar to the current U.S. policy, is a possibility. Alternatively, purchase rates could be designed with system requirements in mind, establishing a rate structure which would bring on stream the most efficient cogeneration applications subject to system capacity requirements. If this resulted in purchase rates below avoided cost, the incremental benefits accruing to the utility could be cycled back to the ratepayers. As a corollary to the above, **utilities should investigate the option of time-of-use based purchase rates,** thereby maximizing the system configuration benefits accruing from cogeneration development. Where sales are made on a firm basis and the utility requires additional system capacity, a capacity charge should be included in the buyback rate.

6.2 Utility Service Policies

The majority of respondents to the industry survey identified the ability to wheel power to plants located away from the cogeneration site as a significant factor in encouraging cogeneration development. Wheeling introduces two distinct benefits to the analysis. From an industry perspective, access to wheeling opens the option of a provincial or regional cogeneration development strategy, as opposed to assessment of plant- or site-specific alternatives. A single installation designed to service the electricity requirements of a number of plants would likely exhibit a superior financial profile, due to the increased electricity offset credits accruing to the project. From a provincial/societal perspective, access to the utility transmission system can allow for a more efficient sizing of cogeneration systems and exploitation of economies of scale, resulting in a more efficient utilization of scarce resources.

It is therefore recommended that, where they have not already done so, utilities develop and implement policies regarding the wheeling of power for prospective cogenerators. In the interest of the utility and the ratepayers, adequate compensation should be provided for the use of this transmission service, sufficient to cover the incremental costs of operation, maintenance, administration and, where applicable, a portion of the capital cost incurred in the case of new facilities required for the delivery of power. Ideally, such compensa-

tion should be negotiated on a case-by-case basis (rather than legislated) to allow for consideration of project-specific costs or benefits to the utility.

At a more general level, a number of respondents commented that, given the importance of the industry-utility interface to the financial and technical feasibility of a cogeneration project, it is critical that the company know with some certainty the requirements, costs and procedures involved in the interconnection. As noted above, many of these interface requirements are of a technical nature and could be worked out among the players involved. However, it is recommended that, **where they have not already done so, utilities develop published guidelines regarding the terms and conditions for interconnection, including technical requirements (metering, switching, maintenance, and so on), charges for standby power, and other aspects of the utility-cogenerator interface.** Planning, assessment and implementation of cogeneration projects will be greatly enhanced by the development of a planning environment that is as certain as is possible for all participants.

Finally, utilities should initiate (or continue to offer) programs providing technical, analytical and feasibility support to companies considering implementation of cogeneration technology.

6.3 Public Policy

As noted earlier, industrial cogeneration offers potential benefits not only from the cogenerator's perspective but from a provincial planning perspective as well. Cogeneration provides a flexible option for meeting load requirements in remote regions, a source of inexpensive power in relatively high-cost utility jurisdictions, a vehicle for addressing waste management concerns, and a cost-effective option for more efficiently utilizing scarce energy resources. As a result, cogeneration should be considered as a planning resource in the same manner as utility-owned generation sources. More specifically, **provincial governments should address the potential for, and limitations of, cogeneration development (along with alternative parallel generation technologies) within the context of long-term electricity supply strategies and options.** This applies equally to provinces with current surplus capacity on the provincial utility generation system.

Provincial governments should reassess the option of providing direct financial assistance for cogeneration developments which exhibit economic potential but inadequate private, financial returns. This assistance could be provided directly from governments or through the electric utilities, to the extent that cogeneration is less expensive than the utility's marginal generation source, after accounting for all public and private costs and benefits. Such assistance could take a number of forms--direct capital grants, low interest loans, tax relief, and so on. In this regard, the federal government should continue its current practice of extending Class 34 accelerated capital cost recovery status to qualifying cogeneration facilities.

In the final analysis, the development of industrial cogeneration within an overall electricity supply framework must be assessed from the standpoint of the ratepayer. In all cases where a cogenerator-utility interface is being considered, the ratepayer should be financially indifferent to this development and, where applicable, to the sourcing of incremental power through surplus power sales from a cogenerator or additional capacity from the utility-owned generation system. This implies that cogeneration developments yielding surplus power at costs above the marginal cost of utility system power should not be pursued as a source of system power. It also implies that the benefits arising from utility sourcing of power at prices below system marginal costs should flow through to the ratepayer.

APPENDIX A

EXAMPLE OF UTILITY INTERCONNECTION REQUIREMENTS FOR COGENERATORS

PARALLEL GENERATION
INTERCONNECTION REQUIREMENTS

1.0 INTRODUCTION

The purpose of this document is to provide guidance to individuals and organizations intending to operate an electrical generation system in parallel with Ontario Hydro's Distribution Electricity System (DES), ie, below 50 kilovolts. While most of the information also applies to higher voltage interconnections, specific details will be provided on request.

As it is impossible to describe all the permutations and combinations of generation systems and supply system conditions, the information contained in this document should be treated as a guide only. Details must be verified in writing through the Manager-Marketing in the appropriate Regional Office listed in Appendix I.

The information does not necessarily apply where the parallel generation site is within the enfranchised area of a municipal electric utility. In such cases the utility concerned must be contacted for direction.

2.0 POINT OF DELIVERY

Normally there will be only one point of physical connection between the parallel generator's system and the DES, usually at the parallel generator's property line. At this point of delivery, the parallel generator will be required to install a visual common point of isolation (normally a manually operated switch suitable to Ontario Hydro) capable of being locked in either the open or closed position, or of having the fuses removed. For safety reasons, this point of isolation will be under the operating control of Ontario Hydro.

3.0 TECHNICAL REQUIREMENTS - GENERAL

Parallel generation interconnected to the Ontario Hydro DES must not adversely affect:

- the health and safety of the general public,
- the health and safety of Ontario Hydro personnel in the performance of their duties in either normal or emergency situations,
- equipment owned and operated by Ontario Hydro,
- the security and reliability of the DES, and
- the quality of the electrical supply to other Ontario Hydro customers.

The parallel generator will be responsible for ensuring that:

- appropriately certified and rated equipment is correctly installed,
- personnel involved in operating and maintaining the plant are properly trained in operation and safe working procedures,
- maintenance is carried out on a regular basis by certified personnel,
- reasonable care is taken to protect the public from hazards associated with the generation system,
- the facility is inspected and approved by Ontario Hydro's Electrical Inspection Department, and
- the installation meets all the requirements of Federal, Provincial and Municipal statutes, regulations, by-laws and codes which pertain to the installation and its performance.

4.0 TECHNICAL CONSIDERATIONS - PRODUCT QUALITY

4.1 General

Product quality can be defined in terms of the deviation of a parameter such as voltage or frequency from a pre-defined norm. Ontario Hydro has established a set of standards within which the electrical network, in Ontario, is operated. To maintain the integrity of the electrical supply to the general public, the parallel generator must also adhere to these guidelines.

4.2 Voltage

Ontario Hydro operates its system within CSA standard C235-1969 (R1979) entitled "Preferred Voltage Levels for AC Systems, 0 - 50,000 volts," which recommends voltage variation limits on customer circuits.

Any parallel generator's system interconnected with Ontario Hydro's system must not cause voltages, as measured at affected customer service entrances to deviate more than the amounts indicated in the CSA standard.

4.3 Frequency

As Ontario Hydro is a part of the interconnected North American power grid, the steady state system frequency is very stable, normally 60 $\pm$ .06 Hz. However, during infrequent system disturbances, frequency transients result in slight deviations

from this range. All equipment installed as a part of a parallel generator's system must be able to withstand steady state frequency fluctuations.

4.4 Power Factor

Induction generators draw their reactive power requirement from the utility supply system, thus the power factor, as seen by the utility, may be quite low. Since low power factor results in system inefficiency and increases operating costs, Ontario Hydro tries to maintain a power factor of 0.90 or greater. Power factors of less than 0.90 result in increased power bills to the parallel generator.

Synchronous generators can provide reactive power, thus lagging power factor is not usually a problem. At some times however, the synchronous machine may operate under a leading power factor, ie: producing more vars than required to magnetize the generator core. As the implications of this are very much location dependent Ontario Hydro requires parallel generators with synchronous generators to operate as near unity power factor as possible. The production of vars will have no affect on customer payments or charges.

4.5 Voltage Flicker

Voltage flicker is described as an increase or decrease in voltage over a short period of time, normally associated with fluctuating load. The characteristics of a particular flicker problem will depend on the characteristics of the corresponding load (percentage voltage dip, frequency of occurrence). This type of problem may arise during the start-up of an induction generator as the large starting current may cause the voltage to drop considerably. All parallel generators must take steps to minimize flicker problems. If voltage flicker problems arise, Ontario Hydro will use the criteria outlined in Figure 1 to determine whether or not the flicker is objectionable. If the problem is found to be significant, the parallel generator will be required to take corrective action.

4.6 Phase Unbalance

A parallel generator's system may utilize three phase or single phase generators.

(a) Voltage Unbalance

If the generator is three phase it must provide balanced open circuit voltage.

If the generator is to supply single phase power, there is a possibility of unbalanced voltages on the local DES. Ontario Hydro attempts to provide balanced three phase voltage at the point of delivery to a customer (within 1%). If the effect of a parallel generator is to cause a phase voltage unbalance in excess of 3%, Ontario Hydro will attempt to redistribute the loading of the DES feeder. If the voltage is still unbalanced by more than 1% after this action has been taken, the parallel generator may be asked to limit the output of the unit.

Voltage unbalance will be determined as follows:

$$= \frac{(\text{maximum phase/neutral voltage} - \text{average phase/neutral voltage})}{\text{average phase/neutral voltage}} \times 100$$

$$< 1\%$$

(b) Current Unbalance

Current unbalances are usually associated with the loading of the feeder under question. Ontario Hydro will attempt to rectify unbalanced current problems by redistributing load.

4.7 Harmonics

Harmonics, in this context, refer to electrical waveforms of an exact multiple of the base supply frequency (60 Hz).

If harmonic voltages and currents are generated by the parallel generator's equipment, propagation of these into the Ontario Hydro DES shall be limited so that quantities shall not exceed the following values:

(a) I.T., balanced, per phase, 5000 amperes
(b) I.T., residual 250 amperes
(c) Harmonic Factor (HF): voltage on a general feeder, HF not to exceed 0.03; on a dedicated feeder, HF not to exceed 0.05.

If a harmonics problem is traced to a parallel generator's system, the parallel generator will be required to take corrective action.

5.0 TECHNICAL CONSIDERATIONS - PROTECTION, CONTROL AND SAFETY

5.1 Fault Protection

The parallel generator's protection system must be capable of automatically responding to two types of faults; internal (within the parallel generator's system) and external (in the DES).

The following information relating to DES automatic protection system can be obtained through the appropriate Regional Manager-Marketing.

1. DES maximum and minimum fault values (3Ø and Line to ground) at the proposed point of interconnection.

2. Details on service ampacities and associated transformer capacities.

3. Details on the settings, sequence of operation and other characteristics of breakers, reclosers and fuses associated with the DES feeder to which the generator is to be connected.

4. Transient design overvoltages for the supply voltage level.

Automatic protection and control systems will be evaluated on a case by case basis. In general, the following criteria will be used to evaluate fault protection schemes.

(a) The proposed protection scheme must co-ordinate with existing Ontario Hydro line protections and isolate the parallel generation system from the DES in the event of an abnormal condition within the parallel generator's system eg, an internal fault.

(b) The proposed protection scheme must automatically isolate the parallel generator's system from the DES in the event of a fault or trip operation on the DES within 3.0 seconds of the occurrence.

(c) The proposed protection scheme may be required to be interlocked to prevent interconnection of the parallel generator's system to the DES in the event of abnormal DES conditions. These conditions include a "dead" feeder, or a feeder on which further disturbances (ie sequenced reclosures) are likely to occur.

In general, a parallel generator's system must be completely disconnected from the DES in the event of a fault (internal or external to the parallel generator's system) or feeder trip operation. Re-connection procedures will be stipulated in an operating agreement.

Backfeed from the parallel generator's system to a tripped DES feeder can cause injury to personnel and/or equipment damage. This condition must not occur.

The minimum functional requirements for protective equipment will be specified by Ontario Hydro on a case by case basis, consistent with the characteristics of the DES at the proposed point of interconnection and the size and type of generators.

In all cases, the protection scheme will include:

- overcurrent protection (possibly directional)
- over/under voltage protection

Additional protection for the parallel generator's equipment may include the following (the need for these is determined by the nature and type of installation):

(i) reverse power protection

(ii) over/under frequency protection

(iii) generator overload protection (thermal)

(iv) voltage detection to trip for loss of balanced three phase voltage (3 phase generation only)

(v) appropriate prime mover protection (eg auto shutdown on loss of load)

(vi) ground fault protection

5.2 Synchronization

Induction machines do not require synchronization and may be started as induction motors using power from the DES. Like any large motor, these units must not cause unacceptable voltage (flicker) or frequency deviations on start up. If this is the case, Ontario Hydro may limit the number of start up operations within a set time period, or require an alternative method of start up.

APPENDIX B

CANADIAN ENERGY RESEARCH INSTITUTE SURVEY OF CANADIAN CORPORATE ATTITUDES TOWARDS COGENERATION

CERI CONFIDENTIAL SURVEY OF CANADIAN CORPORATE ATTITUDES TOWARDS COGENERATION

GENERAL INFORMATION

A.1 Please specify your plant's major products _____

A.2 What fuels are currently used in your plant? _____

A.3 What is the maximum electric power demand in your plant?

( ) 0 - 5 MW
( ) 6 - 20 MW
( ) 21 - 40 MW
( ) 41 MW or more

What is the total annual electric energy consumption in your plant?

( ) 0 - 100 GW.h
( ) 101 - 200 GW.h
( ) 201 GW.h or more

A.4 What percentage of your plant's annual operating cost is made up by electricity and fuel costs?

( ) 0 - 3.0 percent
( ) 3.1 - 6.0 percent
( ) 6.1 percent or more

EXISTING/PLANNED COGENERATION ACTIVITY

B.1 Has your plant practiced cogeneration in the past but since discontinued that activity? YES ( ) NO ( )
If YES, why was it discontinued? _____

B.2 Does your plant currently cogenerate? YES ( ) NO ( ). If YES, what is your cogeneration capacity? _____ kW

B.3 Are you currently building and/or planning to build a cogeneration facility at your plant? YES ( ) NO ( )
IF YES, what is your expected cogeneration capacity? _____ kW

If you answered NO to questions B.2 and B.3 then go to question B.7.

B.4 What cogeneration technology does/will your plant utilize?

( ) Steam Turbine
( ) Gas Turbine
( ) Internal Combustion Engine
( ) Other (describe) _____

B.5 What fuel(s) does/will your cogeneration equipment use? _____

B.6 What were the key technical, economic, and other factors that prompted your company to invest in cogeneration?

B.7 How significant are each of the following factors in constraining your plant's use of cogeneration?

a) TECHNICAL FACTORS

	Very Significant	Significant	Not Significant
- difficulty of retrofitting existing plant	( )	( )	( )
- inappropriate balance of thermal and electric loads	( )	( )	( )

- size of thermal load	( )	( )	( )
- seasonal continuity in thermal load	( )	( )	( )
- daily continuity in thermal load	( )	( )	( )
- availability of suitable technology	( )	( )	( )
- site (e.g., space) contraints	( )	( )	( )
- reliability requirements	( )	( )	( )
- other (specify) _____	( )	( )	( )

b) FINANCIAL FACTORS

	Very Significant	Significant	Not Signif
- availability of capital	( )	( )	( )
- priority of cogeneration in relation to other projects	( )	( )	( )
- return on investment	( )	( )	( )
- availability and cost of fuels	( )	( )	( )
- operation and maintenance costs	( )	( )	( )
- other (specify) _____	( )	( )	( )

c) UTILITY POLICY

	Very Significant	Significant	Not Signif
- existing electricity rates	( )	( )	( )
- buyback rates	( )	( )	( )
- standby charges	( )	( )	( )
- interconnection costs	( )	( )	( )
- availability of technical assistance	( )	( )	( )
- other (specify) _____	( )	( )	( )

d) GOVERNMENT INVOLVEMENT

	Very Significant	Significant	Not Signif
- length and cost of legal procedures	( )	( )	( )
- possiblity of being subjected to utility-like regulation	( )	( )	( )
- environmental protection legislation	( )	( )	( )
- other (specify) _____	( )	( )	( )

e) COMPANY ATTITUDES AND CONSTRAINTS

	Very Significant	Significant	Not Signif
- advice of consultants who investigated cogeneration on our behalf	( )	( )	( )
- electricity production is not our business	( )	( )	( )
- availability of expertise	( )	( )	( )
- research and development requirements	( )	( )	( )
- availability of information	( )	( )	( )
- other (specify) _____	( )	( )	( )

C. POTENTIAL COGENERATION ACTIVITY

C.1 Are there any wastes or by-products generated at your plant which are not currently, but could be used as a fu source? YES ( ) NO ( ) If YES, please list them. _____

C.2 What is the minimum after-tax internal rate or return required to construct a cogeneration facility at your plant?

( ) 0 - 20 percent
( ) 21 - 30 percent
( ) 31 percent or more

What is the maximum simple before-tax payback period required for the construction of a cogeneration facility at your plant?

( ) 0 - 2.0 years
( ) 2.1 - 4.0 years
( ) 4.1 years or more

3 How significant would each of the following factors be in encouraging your plant to install a cogeneration facility?

	Very Significant	Significant	Not Significant
a) TECHNICAL FACTORS			
- improvement in cogeneration technology	( )	( )	( )
- other (specify) _____	( )	( )	( )
b) FINANCIAL FACTORS			
- easing of budget constraints	( )	( )	( )
- a significant drop in fuel costs	( )	( )	( )
- joint utility/cogenerator financing	( )	( )	( )
- financing provided by an outside organization other than the utility	( )	( )	( )
- utility ownership of cogeneration equipment with steam sales back to plant owner	( )	( )	( )
- other (specify) _____	( )	( )	( )
c) UTILITY POLICY			
- a significant rise in electricity rates	( )	( )	( )
- utility cooperation in running of facility	( )	( )	( )
- higher buyback rates	( )	( )	( )
- other (specify) _____	( )	( )	( )
d) GOVERNMENT INVOLVEMENT			
- more involvement in promotion/demonstration projects	( )	( )	( )
- greater tax relief	( )	( )	( )
- greater availability of capital grants and loans	( )	( )	( )
- legislation to establish "rules" for cogeneration re:			
- interconnection with utility	( )	( )	( )
- formulae for buyback rates	( )	( )	( )
- sale of surplus power to utility	( )	( )	( )
- wheeling arrangements	( )	( )	( )
- other (specify) _____	( )	( )	( )

ERAL COMMENTS

What other comments do you have pertaining to cogeneration, or to this questionnaire?

_____

_____

_____

THANK YOU FOR YOUR COOPERATION

APPENDIX C

CANADIAN ENERGY RESEARCH INSTITUTE SURVEY OF UTILITY ATTITUDES TOWARDS COGENERATION

CERI CONFIDENTIAL TELEPHONE SURVEY OF UTILITY ATTITUDES TOWARDS INDUSTRIAL COGENERATION

o you know how much industrial cogeneration capacity currently exists in your service area? YES ( ) NO ( )
f YES, what is that capacity? _____ kW

ave you assessed how much undeveloped industrial cogeneration capacity exists in your service area? YES ( ) NO ( )
f YES, what is that estimated capacity? _____ kW

ow significant are the following potential benefits of developing industrial cogeneration facilities relative to your
n sources of generation?

	Very Significant	Significant	Not Significant
- lower capital costs per kW for new generating capacity	( )	( )	( )
- lower construction risks	( )	( )	( )
- increased flexibility due to smaller units	( )	( )	( )
- increased flexibility due to shorter lead times	( )	( )	( )
- greater efficiency in the use of fuel supplies	( )	( )	( )
- reduced transmission losses	( )	( )	( )
- reduced transmission requirements and/or constraints	( )	( )	( )
- greater stability of the grid due to increased diversity of generating units	( )	( )	( )
- lower "concentration" of environmental impacts	( )	( )	( )
- improved public image of utility by encouraging cogeneration	( )	( )	( )
- other (specify) _____	( )	( )	( )
_____	( )	( )	( )

w significant are the following concerns in your utility's view towards an expanded role for industrial cogenera-
on in the province?

	Very Significant	Significant	Not Significant
- loss of base load	( )	( )	( )
- aggravation of existing/projected surplus capacity	( )	( )	( )
- short-term reliability and maintenance of cogeneration equipment	( )	( )	( )
- need to provide standby capacity for cogenerator	( )	( )	( )
- long-term availability of cogenerated power (survival of the industry, etc.)	( )	( )	( )
- lack of direct operating control (e.g., dispatch) over cogeneration facilities	( )	( )	( )
- risk to ratepayers	( )	( )	( )
- additional complexity of planning/regulatory process	( )	( )	( )
- other (specify) _____	( )	( )	( )
_____	( )	( )	( )

your utility considered, or would your utility be willing to consider, the following measures for encouraging
eneration development in your service area?

	Has Considered	Would Consider	Would Not Consider
- capacity credits for firm power purchases from cogenerator	( )	( )	( )
- higher buyback rates for firm power purchases from cogenerator	( )	( )	( )
- wheeling of power for cogenerator	( )	( )	( )

- conducting demonstration projects of cogeneration equipment	( )	( )	( )
- conducting technical and management programs (seminars, workshops, etc.)	( )	( )	( )
- undertaking feasibility studies of cogeneration projects for industry	( )	( )	( )
- providing personnel for construction and/or operation of cogeneration facility	( )	( )	( )
- providing financial incentives (grants, subsidies etc.) to industry	( )	( )	( )
- participating in joint ventures with industry to develop cogeneration systems	( )	( )	( )
- owning and operating a cogeneration facility with energy sales to industry	( )	( )	( )
- operating a facility owned by industry	( )	( )	( )
- constructing (and owning) a facility operated by industry	( )	( )	( )
- participating in a third party arrangement where third party buys power from cogenerator and sells to utility	( )	( )	( )
- other (specify) _____	( )	( )	( )
_____	( )	( )	( )

6. Do you have any general comments with regard to industrial cogeneration or this questionnaire?

_____

_____

_____

_____

_____

_____

THANK YOU

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